associated with major river systems (e.g., Missouri, Platte, and Mississippi Rivers). As with other HCAs, these locations will be subject to higher levels of inspection, as per 49 CFR Part 195, in order to reduce the probability of pipeline incident.

4.3.4 Distribution of Risk Among HCAs

Up to this point in this document, risk was assumed to be uniformly distributed along the Keystone Pipeline system. This provides a broad overview of risk along the entire system. However, in reality risk is unevenly distributed along the pipeline. Due to Homeland Security reasons, the precise risk for specific locations is highly confidential. Nevertheless, Keystone is providing a preliminary evaluation of risk to HCAs that incorporates site-specific risk factors. Per federal regulations (Integrity Management Rule, 49 CFR Part 195), the site-specific evaluation of risk is an ongoing process and is regulated by the USDOT.

If risk was evenly distributed along the entire length of pipeline, then the sum of the maximum spill volumes from 430 of the 1,720 segments would account for 25 percent of the total maximum spill volume for the entire Keystone Pipeline system. However, risk is not distributed evenly across the system. By summing the higher maximum spill volumes, the number of segments accounting for 25 percent of the total maximum spill volume varies between 39 and 66 segments, depending on the type of product transported and the amount of throughput. **Table 4-21** quantifies the number of segments along the entire length of the Keystone Pipeline system that contribute the greatest amount to risk, defined as the number of segments that contribute 25 percent of the total maximum spill volume for the entire Keystone Pipeline system.

Table 4-21 Segments Accounting for 25 Percent of Total Maximum Spill Volume

	Diluted Bitumen		Synthetic Crude	
	435,000 bpd throughput	591,000 bpd throughput	435,000 bpd throughput	591,000 bpd throughput
Number of segments that contribute 25 percent of total maximum spill volume	66	39	62	66
Length of pipe that contributes to 25 percent of the total maximum spill volume (miles)	21	9	19	20

Many of these higher risk segments are not located within HCAs. **Table 4-22** identifies the miles of HCAs crossed by these higher risk segments. None of the higher risk segments are located within populated area HCAs. There are some ecologically sensitive areas and drinking water USAs that will be crossed by the higher risk segments. Appendix B incorporates the risk associated with each pipeline segment into Keystone's preliminary evaluation of risk to HCAs.

Table 4-22 Length of Higher Risk Segments Within HCAs (miles)

	Diluted Bitumen		Synthetic Crude	
Type of HCA	435,000 bpd throughput	591,000 bpd throughput	435,000 bpd throughput	591,000 bpd throughput
Populated Areas	0.0	0.0	0.0	0.0
Ecologically Sensitive Areas	8.0	6.6	11.0	11.2
Drinking Water	5.3	0.0	5.3	6.2

To protect these sensitive resources, HCAs would be subject to a higher level of inspection per USDOT regulations. Federal regulations require periodic assessment of the pipe condition and correction of identified anomalies within HCAs. Keystone will develop management and analysis processes that integrate available integrity-related data and information and assess the risks associated with segments that can affect HCAs.

Based on Keystone's preliminary assessment of HCAs (Appendix B), some valve locations have been moved and additional valves have been added to protect HCAs. These updated locations have been submitted to the DOS in the March 2007 filing. In addition, Keystone will develop and implement a risk-based integrity management program (IMP). The IMP will use state-of-practice technologies applied within a comprehensive risk-based methodology to assess and mitigate risk associated with all pipeline segments including HCAs.

5.0 Keystone's Pipeline Safety Program

Pipelines are one of the safest forms of crude oil transportation and provide a cost effective and safe mode of transportation for oil on land. Overland transportation of oil by truck or rail produces higher risk of injury to the general public than the proposed pipeline (USDOT 2002). The Keystone Pipeline system will be designed, constructed and maintained in a manner that meets or exceeds industry standards.

Historically, the most significant risk associated with operating a crude oil pipeline is the potential for third-party excavation damage. The pipelines will be built within an approved right-of-way (ROW) and visible signs will be installed at all road, railway, and water crossings. Keystone also will mitigate third-party excavation risk by implementing a comprehensive Integrated Public Awareness program focused on education and awareness in accordance with 49 CFR 195.440 and API RP1162. Further, Keystone's operating staff will complete regular visual inspections of the ROW (at least once every 3 weeks and a minimum of 26 times per year) as per 49 CFR 195.412 and monitor activity in the area to prevent unauthorized trespass or access.

Keystone will have a maintenance, inspection, and repair program that ensures the integrity of its pipeline. Keystone's annual Pipeline Maintenance Program (PMP) will be designed to maintain the safe operation of the pipeline system. The PMP will include routine aerial patrol of the ROW, periodic inline inspections and cathodic protection readings underpinned by a company wide goal to ensure facilities are reliable and in service. Data collected in each year of the program will be fed back into the decision making process for the development of the following year's program. In addition, the pipeline system will be monitored 24 hours a day, 365 days a year from the oil control center using leak detection systems and supervisory control and data acquisition (SCADA). During operations, Keystone will have an Emergency Response Program in place to manage a variety of events.

6.0 Conclusion

In summary, this conservative analysis of the proposed Keystone Pipeline system shows that the predicted frequency of incidents is low, the probability of a large spill occurring is low, and, consequently, risk of environmental impacts is minimal. Compliance with regulations, application of Keystone's IMPs and its ERP, as well as adherence to safety procedures will help to ensure long-term environmentally sound and safe operation of the pipeline.

7.0 REFERENCES

California State Fire Marshal. 1993. Hazardous Liquid Pipeline Risk Assessment. Office of the State Fire Marshal, Pipeline Safety Division, Sacramento, California. 187 pp.

Center for Disease Control – National Center for Health Statistics for 2003. Online data summary. URL:http://www.cdc.gov/nchs.

Couch, J. A. and J. C. Harshbarger. 1985. Effects of carcinogenic agents on aquatic animals: an environmental and experimental overview. J. Environ. Sci. Health, Part C, Environ. Carcin. Rev. 3:63-105.

Davies, W. E., J. H. Simpson, G. C. Ohlmacher, W. S. Kirk, and E. G. Newton. 1984. Engineering Aspects of Karst. U.S. Geological Survey, National Atlas, scale 1:75,000.

European Gas Pipeline Incident Data Group (EGIG). 2005. Gas Pipeline Incidents, 6th EGIG-report 1970-2004. Doc Number EGIG 05.R.0002, December 2005.

Illinois State Geological Survey (ISGS). 2004. Online Coal maps, publications, and coal resource data. URL: http://www.isgs.uiuc.edu/isgshome/coal.htm. website updated September 16, 2004. Site reviewed February 3, 2006.

Kastning, E. H. and K. M. Kastning. 1999. Misconceptions about Cave and Karst: Common Problems and Educational Solutions, National Cave and Karst Management Symposium, P. 99-106.

Lawrence, J.F. and D.F. Weber. 1984. Determination of polycyclic aromatic hydrocarbons in some Canadian commercial fish, shellfish, and meat products by liquid chromatography with confirmation by capillary gas chromatography with fluorescence detection. J. Agric. Food Chem. 32:794-797.

Muller, H. 1987. Hydrocarbons in the freshwater environment. A Literature Reivew. Arch. Hydrobiol. Beih. Ergebn. Limnol 24:1-69.

Neff, J. M. 1979. Polycyclic aromatic hydrocarbons in the aquatic environment. Applied Science publ. Ltd., London. 262 pp.

Neff, J.M. and J.W. Anderson. 1981. Response of Marine Animals to Petroleum and Specific Hydrocarbons. Applied Science Publishers, London. 177 pp.

O'Rourke, M.J. and Palmer. 1996. Earthquake Performance for Gas Transmission Pipelines. Earthquake Spectra 12(3):493.

Sharp, B. 1990. Black oystercatchers in Prince William Sound: oil spill effects on reproduction and behavior in 1989. *Exxon Valdez Trustees' Study-Bird Study Number 12*. U.S. Fish and Wildlife Service, Portland, Oregon.

Shiu, W.Y. A. Maijanen, A.L.Y. Ng and D. Mackay. 1988. Preparation of aquesous solutions of sparingly soluble organic substances: II. Multicomponent systems – hydrocarbon mixtures and petroleum products. Environ. Toxicol. Chem. 7:125-137.

Stubblefield, W. A., G. A. Hancock, W. H. Ford, H. H. Prince, and R. K. Ringer. 1995. Evaluation of toxic properties of naturally weathered Exxon Valdez crude oil to surrogate wildlife species. Pp. 665-692. In: P.

G. Wells, H. N. Butler, and J. S. Hughes 9eds)., *Exxon Valdex Oil Spill: Fate and Effects in Alaskan Waters, ASTM STP 1219*. American Society for Testing and Materials, Philadelphia, Pennsylvania.

U.S. Environmental Protection Agency (USEPA). 2001. ECOTOX database. Internet database for aquatic and terrestrial toxicity data. http://www.epa.gov/ecotox/.

USEPA. 2000. AQUIRE ECOTOX database. Internet database for aquatic toxicity data. http://www.epa.gov/ecotox/.

U.S. Geological Service (USGS). 1998. Groundwater Contamination by Crude Oil near Bemidji, Minnesota. U.S. Geological Survey Fact Sheet 084-98, September 1998.

U.S. Geological Service (USGS). 2007. website. http://waterdata.usgs.gov\nws\rt.

U.S. Department of Transportation. 2002. Office of Pipeline Safety Pipeline Statistics. Website: http://ops.dot.gov/stats/ stats.htm

U.S. Department of Transportation – National Pipeline Mapping System (USDOT-NPMS). 2005. Confidential data from the NPMS database.

U.S. Department of Transportation. 2007. Office of Pipeline Safety Pipeline Statistics. Website: http://ops.dot.gov/stats/IA98.htm

West, W. R., P.A. Smith, P. W. Stoker, G. M. Booth, T. Smith-Oliver, B. E. Butterworth, and M. L. Lee. 1984. Analysis and genotoxicity of a PAC-polluted river sediment. Pages 1395-1411 In: M. Cooke and A. J. Dennis (eds.). Polynuclear aromatic hydrocarbons: mechanisms, methods, and metabolism. Battelle Press, Columbus, Ohio.

Wilson, L. 1986. Vulnerable aquifers. Pp. 60-61 in J.L. Williams, ed. New Mexico in Maps, New Mexico Press, Albuquerque, New Mexico.

8.0 Glossary

Accidental Release

An accidental release is an unplanned occurrence that results in a release of oil or natural gas from the pipeline.

Acute exposure

Exposure to a chemical or situation for a short period of time.

Acute toxicity

The ability of a substance to cause severe biological harm or death soon after a single exposure or dose.

Adverse effect

Any effect that causes harm to the normal functioning of plants or animals due to exposure to a substance (i.e., a chemical contaminant).

Algae

Chiefly aquatic, eucaryotic one-celled or multicellular plants without true stems, roots and leaves that are typically autotrophic, photosynthetic, and contain chlorophyll. They are food for fish and small aquatic animals.

Aquifer

An underground layer of water-bearing permeable rock, or unconsolidated materials (gravel, sand, silt or clay) from which groundwater can be usefully extracted using a water well.

Barrel

A barrel is a standard measure of a volume of oil and is equal to 42 gallons.

Benthic invertebrates

Those animals without backbones that live on or in the sediments of a lake, pond, river, etc.

Bioavailability

How easily a plant or animal can take up a particular contaminant from the environment.

Biodegradation

Biodegradation is the breakdown of organic contaminants by microbial organisms into smaller compounds. The microbial organisms transform the contaminants through metabolic or enzymatic processes. Biodegradation processes vary greatly, but frequently the final product of the degradation is carbon dioxide or methane.

BPD

Abbreviation for barrels per day

Cathodic Protection System

A technique to provide corrosion protection to a metal surface by making the surface of the metal object the cathode of an electrochemical cell. In the pipeline industry that is done using impressed current. Impressed current Cathodic Protection (ICCP) systems use an anode connected to a DC power source (a cathodic protection rectifier).

Chronic toxicity

The capacity of a substance to cause long-term poisonous health effects in humans, animals, fish, and other organisms. Biological tests that use sublethal effects such as abnormal development, growth, and reproduction, rather than solely lethality, as endpoints.

Contaminant

Any physical, chemical, biological, or radiological substance found in air, water, soil or biological matter that has a harmful effect on plants or animals; harmful or hazardous matter introduced into the environment.

Ecosystem

The sum of all the living plants and animals, their interactions, and the physical components in a particular area.

Emergency Flow Restricting Device (EFRD)

An emergency flow-restricting device is a device used to restrict or limit the amount of oil or gas that can release out of a leak or break in a pipeline. Check valves and remote control valves are types of EFRDs.

Exposure

How a biological system (i.e., ecosystem), plant, or animal comes in contact with a chemical.

Event

An event is a significant occurrence or happening. As applicable to pipeline safety, an event could be an accident, abnormal condition, incident, equipment failure, human failure, or release.

Facility

Any structure, underground or above used to transmit a product.

Failure Frequency

Failure frequency is the rate at which failures are observed or are predicted to occur, expressed as events per given timeframe.

Failure Probability

Failure probability is the probability that a structure, device, equipment, system, etc. will fail on demand or will fail in a given time interval, expressed as a value from 0 to 1.

Failure Rate

Failure rate is the rate at which failures occur. It is the number of failure events that occur divided by the total elapsed operating time during which those events occur or by the total number of demands, as applicable.

Geographical Information System (GIS)

A computer data system for creating and managing spatial data and associated attributes.

Habitat

The place where a population of plants or animals and its surroundings are located, including both living and non-living components.

High Consequence Area (HCA)

A high consequence area is a location that is specially defined in USDOT pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment. For oil pipelines, HCAs include high population areas, other population areas, commercially navigable waterways and areas unusually sensitive to environmental damage, including ecologically sensitive areas and drinking water resources. Regulations require a pipeline operator to take specific steps to ensure the integrity of a pipeline for which a release could affect an HCA and, thereby, provide protection of the HCA.

High Population Area

A high population area is an urbanized area, as defined and delineated by the U.S. Census Bureau, which contains 50,000 or more people and has a population density of at least 1,000 people per square mile. High population areas are considered HCAs.

Incident

As used in pipeline safety regulations, an incident is an event occurring on a pipeline for which the operator must make a report to the Office of Pipeline Safety. There are specific reporting criteria that define an incident that include the volume of the material released, monetary property damage, injuries, and fatalities (Reference 49 CFR 191.3, 49CFR 195.50).

Integrity Management Program

An IMP is a documented set of policies, processes, and procedures that are implemented to ensure the integrity of a pipeline. An oil pipeline operator's IMP must comply with the federal regulations (i.e., the Integrity Management Rule, 49 CFR 195).

Integrity Management Rule

The Integrity Management Rule specifies regulations to assess, evaluate, repair, and validate the integrity of hazardous liquid pipelines that, in the event of a leak or failure, could affect HCAs.

Invertebrates

Animals without backbones: e.g., insects, spiders, crayfish, worms, snails, mussels, clams, etc.

LC_{50}

A concentration expected to be lethal to 50 percent of a group of test organisms.

Leak

A leak is a small opening, crack, or hole in a pipeline allowing a release of oil or gas.

Likelihood

Likelihood refers to the probability that something possible may occur. The likelihood may be expressed as a frequency (e.g., events per year), a probability of occurrence during a time interval (e.g., annual probability), or a conditional probability (e.g., probability of occurrence, given that a precursor event has occurred).

Maximum Contaminant Level (MCL)

The maximum level of a contaminant allowed in drinking water by federal or state law. Based on health effects and currently available treatment methods.

National Pipeline Mapping System (NPMS)

The National Pipeline Mapping System is a GIS database that contains the locations and selected attributes of natural gas transmission lines, hazardous liquid trunklines, and liquefied natural gas (LNG) facilities operating in onshore and offshore territories of the United States.

One-Call System

A one-call system is a system that allows excavators (individuals, professional contractors, and governmental organizations) to make one telephone call to underground facility operators to provide notification of their intent to dig. The facility operators or, in some cases, the one-call center can then locate the facilities before the excavation begins so that extra care can be taken to avoid damaging the facilities. All 50 states within the U.S. are covered by one-call systems. Most states have laws requiring the use of the one-call system at least 48 hours before beginning an excavation.

Other Populated Areas

An 'other populated area' is a census designated place, defined and delineated by the U.S Census Bureau as settled concentrations of population that are identifiable by name but are not legally incorporated under the laws of the state in which they are located.

Operator

An operator is a person who engages in the transportation of gas (Reference 49 CFR 192.3) or a person who owns or operates pipeline facilities (Reference 49 CFR 195.2).

Polycyclic Aromatic Hydrocarbons (PAHs)

Group of organic chemicals.

Pipeline

Used broadly, pipeline includes all parts of those physical facilities through which gas, hazardous liquid, or carbon dioxide moves in transportation. Pipeline includes but is not limited to: line pipe, valves and other appurtenances attached to the pipe, pumping/compressor units and associated fabricated units, metering, regulating, and delivery stations, and holders and fabricated assemblies located therein, and breakout tanks.

Playa Lake

A rain-filled small, round depression in the surface of the ground.

Prairie Pothole

Water-holding depressions of glacial origin in the prairies of northern United States and southern Canada. Water is supplied by rainfall, basin runoff and seepage inflow of groundwater.

Receptor

The species, population, community, habitat, etc. that may be exposed to contaminants.

Risk

Risk is a measure of both the likelihood that an adverse event could occur and the magnitude of the expected consequences should it occur.

Sediment

The material of the bottom of a body of water (i.e., pond, river, stream, etc.).

Stressor

Any factor that may harm plants or animals; includes chemical (e.g. metals or organic compounds), physical (e.g. extreme temperatures, fire, storms, flooding, and construction/development) and biological (e.g. disease, parasites, depredation, and competition).

Supervisory Control and Data Acquisition System (SCADA)

A SCADA is a pipeline control system designed to gather information such as pipeline pressures and flow rates from remote locations and regularly transmit this information to a central control facility where the data can be monitored and analyzed.

Throughput

Amount of oil through a pipeline during a specified time.

Toxicity Testing

A type of test that studies the harmful effects of chemicals on particular plants or animals.

Toxicity Threshold

Numerical values that represent concentrations of contaminants in abiotic media (sediments, water, soil) or tissues of plants and animals above which those contaminants are expected to cause harm.

Unusually Sensitive Areas (USAs)

A USA is a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release, as defined in 49 CFR 195.6.

Zooplankton

Small, usually microscopic animals (such as protozoans) found in lakes and reservoirs.

Appendix A

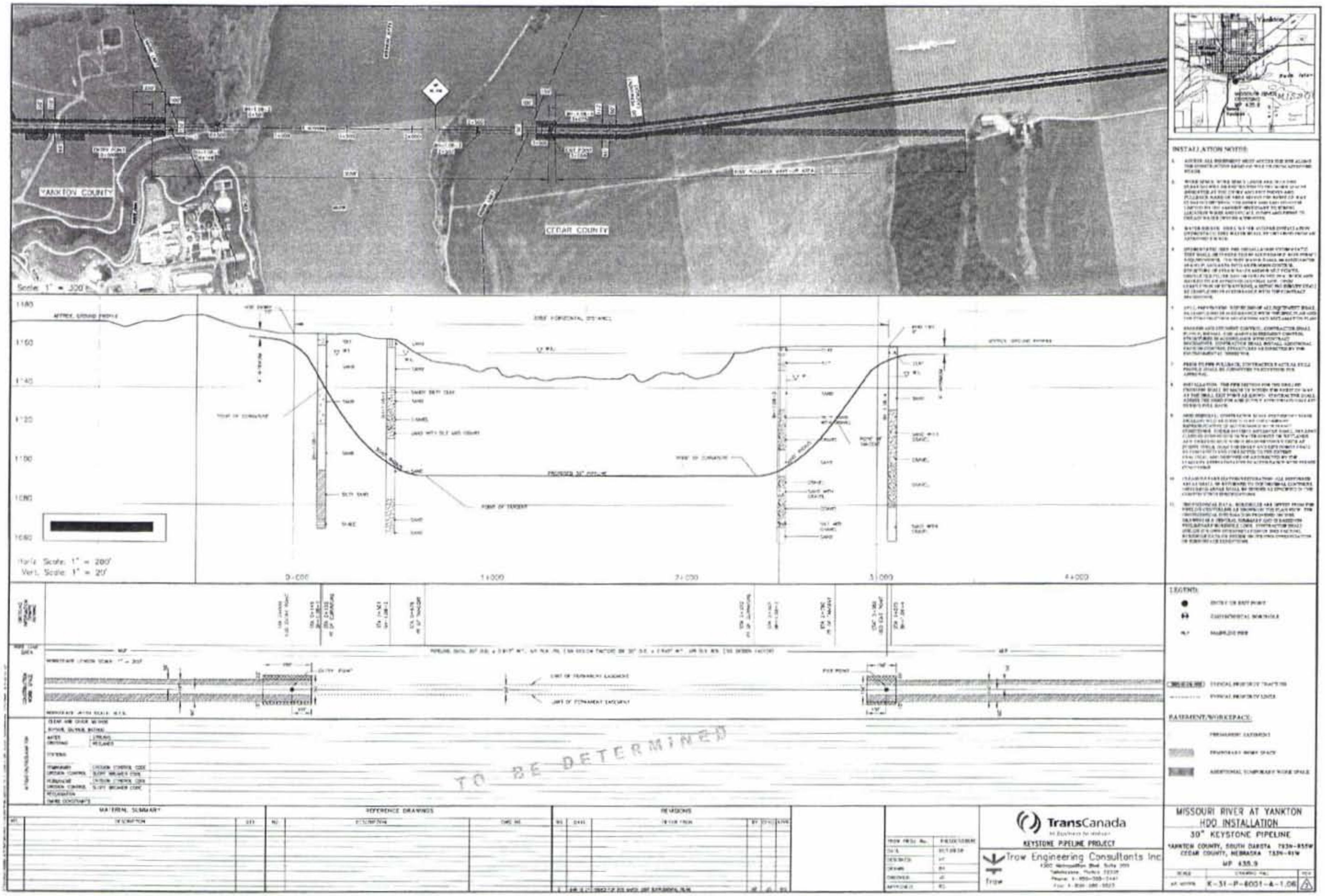
Frequency – Volume Study of Keystone Pipeline

Appendix B

Preliminary HCA Evaluation

(to be filed April 2007)

CONFIDENTIAL



CONFIDENTIAL

DNV ENERGY

Keystone Pipeline Frequency and Volume Analysis

Report for TransCanada Keystone Pipeline L.P.
Report no.: 70020509 Revision 3,
28 March 2007

MANAGING RISK DNV

CONFIDENTIAL

Keystone Pipeline Frequency and Volume Analysis

for

TransCanada Keystone Pipeline L.P.
450 - 1st Street S.W.
T2P 5H1 Calgary, Alberta
CANADA

Client ref:	Meera Kothari PEng		
Report No.:	70020509	Subject Group:	Risk Management
Indexing terms:	Pipeline, Risk, Frequency		
Summary:	DNV Energy is assisting Keystone with risk management and regulatory compliance for the Keystone Pipeline, specifically, assessing the U.S. portion of the Keystone Pipeline to quantify oil spill risk in terms of frequency and volume. This report documents the assumptions and results.		
Prepared by:	*Name and position* Bjørn Nilberg, Principal Consultant		*Signature* Cheryl Stahl for Bjørn Nilberg
Verified by:	*Name and position* Cheryl Stahl, Principal Consultant		*Signature* Cheryl Stahl
	Name and position Susan Norman, Senior Administrative Assistant		*Signature*
Approved by:	*Name and position* David Weimer, Upstream Market Sector Leader		*Signature*
Date of issue:	28 March 2007		
Project No:	70020509		

* *Please use Project No as reference in all correspondence with DNV.*

- [x] No distribution without permission from the client or responsible organizational unit (however, free distribution for internal use within DNV after 3 years)
- [ ] No distribution without permission from the client or responsible organizational unit
- [ ] Strictly confidential
- [ ] Unrestricted distribution

1.0 Introduction

TransCanada Keystone Pipeline, L.P. (Keystone) is proposing the Keystone Pipeline Project, which would transport a nominal 435,000 bpd (591,000 bpd maximum) of crude oil from facilities near Hardisty, Alberta, to Patoka, Illinois and Cushing, Oklahoma.

In the United States (U.S.), the Keystone Pipeline Project will require federal approvals from agencies such as the U.S. Department of State and the U.S. Army Corps of Engineers. In Canada, approvals from the National Energy Board (NEB) will be required. The project may also entail additional local, state, and regional approvals.

DNV Energy is assisting Keystone with risk management and regulatory compliance for the Keystone Pipeline, specifically, assessing the U.S. portion of the Keystone Pipeline to quantify oil spill risk in terms of frequency and volume of potential spills. The outputs will enable refinement of the ecological assessment being conducted for compliance with the National Environmental Policy Act.

This study focuses on quantifying the risk of a spill of crude oil, in terms of the frequency related to a given volume of oil that may potentially be spilled to the environment. This report encompasses an update of a previous study performed in 2006 (DNV 2006). This update estimates the frequency and volume of releases for each segment for three postulated hole sizes, and develops a frequency-volume curve for the pipeline as a whole.

Two throughput scenarios were evaluated, a 435,000 bpd throughput scenario (nominal case) and a 591,000 bpd throughput scenario for two different products: Diluted Bitumen and Synthetic Crude. Revision 0 of this report described the methodology and applied it to an early-design version of the hydraulic profile and design parameters. For this report, an updated hydraulic profile was utilized for the nominal and maximum throughput cases, together with updated information regarding the locations of pump stations, and other design details.

The project background is described briefly in Section 2.0. A methodology overview is presented in Section 3.0.

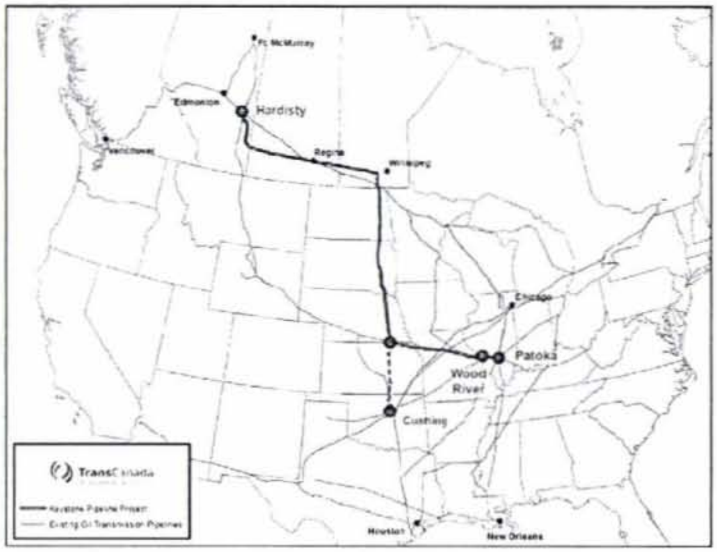
Section 4.0 describes the base leak frequencies and modification factors relevant for Keystone.

Section 5.0 describes the methodology used to calculate realistic maximum spill volumes

The final summary and conclusions are provided in Section 6.0.

This study is a quantitative assessment of risks for the pipeline as a whole and a screening-level assessment of individual segments of the pipeline. Each segment was defined so that it would comprise a virtually consistent risk profile, using the best available quantification techniques to estimate the risk profile of the pipeline.

2.0 Background



The total length of the proposed Keystone Pipeline is 1845 miles (mi), comprising about 767 mi in Canada and 1372 mi in the U.S. The U.S. portion consists of newly-constructed pipeline and up to 27 new pump stations.

The timeline for the project includes submission of major regulatory applications in the U.S. and Canada in Spring 2006, with completion of associated field studies and environmental assessments throughout 2006. Route refinement may continue as commercial requirements and input are gathered from agencies, stakeholders, and design teams.

In 2007, the engineering design is expected to be complete, with the necessary approvals and licenses. The construction and conversion of facilities and startup are anticipated in 2008 and 2009.

The pipeline is expected to be designed and operated within the following key parameters (**Table 2-1**) relevant to spill risk, which were provided by Keystone:

Table 2-1 Key Study Input Parameters

Parameter	Value
Diameter	30 inches and 24 inches (Keystone Mainline); 36 inches Cushing Extension
Above vs. belowground	Belowground mainline; aboveground within pump station battery limits
Pipe wall thickness	30 inch line: 0.375 inches; 24 inch line: 0.343 inches; 36 inch line: 0.45 inches
Remote block valves	26
Check valves	20, each associated with a (powered) manual block valve
Mainline location	In GIS
Pump station locations	In GIS
Leak detection	Capable of detecting a 5% leak in 90 min; and a 53% leak in 5 min
Surveillance	Within U.S. DOT requirements
Hydraulic profile	4 cases for analysis: • 435,000 bpd, Diluted Bitumen, density 940 kg/m^3 • 435,000 bpd, Synthetic Crude, density 865 kg/m^3 • 591,000 bpd, Diluted Bitumen, density 940 kg/m^3 • 591,000 bpd, Synthetic Crude, density 865 kg/m^3

3.0 Methodology

All crude pipeline spills begin with an initiator, or cause, of an initial loss of oil from the pipeline. Once the leak starts, the scenario unfolds in four phases: leak detection, mainline shutdown, leak isolation, and stoppage of flow from the pipe (if possible). The duration of each phase ultimately determines the quantity of crude spilled.

This study segmented the pipeline to allow estimation of leak frequency and realistic maximum leak volume for portions of the pipeline over which the frequency and volume were virtually constant. The frequency of failure for three hole sizes (small, medium, and large) was estimated for each segment by identifying the relevant failure mechanisms specific to the Keystone Pipeline that could impact the frequency (or volume) of leaks. Historical base frequencies were adjusted using project-specific modification factors for each cause of failure.

Each segment was analyzed to estimate the maximum realistic volume of a leak for each hole size from each failure cause. For small and medium hole leaks, it was assumed that a trained response crew would stop the leak within a specified timeframe.

The remainder of this section discusses the potential causes of spills, describes the methodology used for the segmentation process, and presents relevant baseline frequencies and Keystone Pipeline modification factors.

3.1 Causes of Spills

More than 17 factors (not necessarily independent) could influence pipeline spill initiation (**Table 3-1**). These factors were identified via literature review and DNV experience in assessing this type of pipeline risk. It should be noted that the factors are similar but not identical to the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) categories of failure (e.g., third party harm is included as a portion of the excavation damage factor).

Table 3-1 Factors That Could be Considered for Pipeline Spill Initiation

Factor	Description
Flange, seal, and fitting leak	A leak from a flange, seal, or fitting.
Material defect or construction deficiency	Failures due to flaws within the material structure of the pipe, caused by material or manufacturing defects, improper welding, or installation errors.
Corrosion (external or internal)	Failures due to general and pitting type corrosion caused by fluids inside the pipeline or corrosive soils or conditions outside of the pipe.
Corrosion assisted initiators	These are several rather than one, and include operational transients, error in pressure setpoint control, material property deviations, etc.
Hydraulic (pressure surge) event	Overpressure caused by human or mechanical error, combined with overpressure protection failure.
Excavation damage	Excavation equipment damages to underground piping; by Keystone Pipeline maintenance personnel or by third parties. Third party is assumed to be the dominating factor.
Maintenance damage	A leak caused by crews conducting maintenance work on the pipeline.

Factor	Description
Accidental acts	Accidental acts by a third party (such as a hunting accident) that cause a leak (vehicle, train, and aircraft operation were evaluated separately). This study scope excludes strategic, intentional acts, such as planned terrorist attacks.
Human/operator error	Improper performance of maintenance or operating procedures leading to a line failure.
Seismic event	Earthquake or other vigorous displacement of the pipeline due to seismic activity or ground movement.
Settlement	Thaw settlement or frost jacking causes line to buckle.
Slope instability	Avalanche damages piping or instability lead to loss of piping support.
Washout/bridge failure	River bottom pipe exposed by heavy runoff, line may float and buckle. Bridge supports may corrode and cause line failure (no bridge crossings are planned for the Keystone Pipeline System).
Vehicle impact	Line failure due to large vehicles, typically transport trucks, leaving the roadway and impacting the line.
Aircraft impact	Impact fractures underground piping
Train derailment	Impact fractures underground piping
External fire or explosion	Fire impinging on the pipe, or an explosion resulting in a leak.

From the above 17 factors that could influence pipeline spills, six distinct and practically independent causes (from a frequency estimation point of view) were identified as applicable to the Keystone Pipeline and evaluated in detail in this study (see Section 4.0).

1. Corrosion (external or internal)
2. Excavation damage
3. Material defect or construction deficiency
4. Hydraulic (pressure surge) event
5. Washout
6. Seismic events

Table 3-2 lists the factors that were not quantified as separate causes in this study, with explanation.

Table 3-2 Factors not Individually Quantified in this Study

Factor	Reason
Corrosion assisted initiators	This failure frequency is incorporated into other historical causal frequencies (such as hydraulic event and corrosion).
Maintenance damage	This is included in the excavation cause for belowground pipeline
Accidental acts	Accidental harm to the pipeline was considered only credible for aboveground pipe. For the Keystone Pipeline, the only aboveground pipe is within pump stations, which are secured. As a result, this cause was deemed not relevant
Human/operator error	After detailed design and operating procedures are drafted, this cause can be evaluated in detail.
Flange, seal, and fitting leak	There are no flanges in the main pipeline; all valves are welded.
Settlement	Major settlement is often associated with thaw that causes a deformation of the pipe and subsequent pipe failure. DNV was unable to quantify this very low level of risk in the timeframe required with the conceptual level of design currently available for the pipeline. It is unlikely that this risk factor would contribute significantly to the pipeline risk picture, as less than 1% of 1986-2001 recorded incidents were attributable to the OPS category "subsidence".
Slope instability	DNV was unable to quantify this risk with the conceptual level of design currently available for the pipeline.
Vehicle impact	This is defined as a truck-pipe collision with sufficient momentum to break the pipe. The probability of a belowground portion of pipe being affected by a vehicle impact results in a frequency less than 1×10^{-7}, which is not a credible scenario.
Train derailment	DNV was unable to quantify this very low level of risk in the timeframe required with the conceptual level of design currently available for the pipeline. It is unlikely that this risk factor would contribute significantly to the pipeline risk picture.
Aircraft impact	Since the Keystone Mainline is belowground, aircraft impact risk is estimated at less than 1×10^{-6}. This could be further refined and quantified based on sizes of aircraft and activity levels, if desired; however, it is unlikely to contribute to the Keystone Pipeline risk picture.
Fire or explosion	Since the majority of the pipeline is belowground, this is a credible scenario only at the pump stations. The primary sources of ignition might be station equipment fire, agricultural burns, and wildfires.

Distribution of Hole Sizes for Each Cause

A specific distribution of small, medium, and large sized holes was developed and applied for each spill cause (described further in Section 4.0). Note that hole size is not the same as spill volume. Some leaks from small holes could occur for a long period of time and result in a large spill volume because they would not be detected as quickly as some leaks from larger holes.

The estimation of frequency for a given spill volume is linked to hole size, because for any failure cause, one hole size is more or less likely than another. In assessing the distribution of hole sizes for each cause, the failure mechanism and pipe material properties were considered. The size of the hole is a function of many factors including stress levels and material properties such as ductility. For instance, corrosion is characterized by a failure mechanism of slow removal of metal, and therefore is generally prone to result in pinhole-type leaks rather than full bore failures. In contrast, outside forces such as vehicle impact on aboveground pipeline are more likely to cause larger holes.

Three sizes of hole were assessed for each cause:

- Small, equivalent to 0.06 inch diameter hole
- Medium, equivalent to 2 inch diameter hole
- Large, equivalent to 10 inch diameter hole and larger

The representative hole sizes were chosen to allow use of the best statistically significant set of data for pipelines. Further detail regarding the generic data sets used in this analysis is provided in Appendix I.

3.2 Segmentation

The pipeline was segmented for this assessment based on several factors, all related to the physical and environmental characteristics that would create unique failure mechanisms or consequence for various lengths of pipe. These segments were used as the basis for calculating frequency of spill volumes. DNV defined each segment as the length of pipe over which none of the risk characterization parameters changes significantly.

An alternative approach would have been to define each segment by a static geographic distance; however, the current approach was deemed more suitable for any future spill risk studies incorporating consequence of a spill.

Table 3-3 lists the characterization parameters used as inputs to segmentation.

Table 3-3 Segmentation Parameters

Parameter	Related cause or consequence	Discussion
Above versus belowground location of pipeline	Excavation damage Corrosion (external or internal)	The majority of Keystone Pipeline is belowground, with transitions to aboveground only within secure areas at pump stations.
Pipe wall thickness	Excavation damage Corrosion (external or internal)	Wall thickness is a risk factor for both excavation damage and corrosion caused leaks.

Parameter	Related cause or consequence	Discussion
Excavation activity level	Excavation damage	This input factor characterizes segments by the potential for excavation activity. *Road crossings per mile* was the best available data for estimation of excavation activity (because of the potential for impact to the pipe from activities related to roadside drainage ditches and culverts).
Hydraulic event susceptibility	Hydraulic (pressure surge) event	The sections of Keystone Pipeline operating closer to MAOP are assigned greater susceptibility to hydraulic damage in the event of human or mechanical error.
Washout event susceptibility	Washout	The washout event susceptibility is used to identify segments that cross rivers with a potential to remove sediments surrounding the pipe. This will be combined with flood risk levels along the Keystone Pipeline.
Pipeline patrol frequency	NA (related to leak detection time)	The patrol frequency contributes to both the likelihood of finding unauthorized excavation and the timeliness of detection for small hole leaks.
Direct impact on High Consequence Areas (HCA).	Pipelines crossing High Consequence Areas.	Sets of direct impacted HCA as specified by DOT/OPS for Drinking Water (DW), Ecological (ECO) and High Populated Areas (HPO)
Seismic Event susceptibility	Seismic (earth quake) events	Keystone Pipeline is in a very low risk area for seismic activity according to DOT/NPMS.
Flood risk	(Washout)	Combined with washout susceptibility.

A new segment was created at each point where a change in any of the risk characterization parameters occurred. This approach minimized the number of segments necessary to analyze the entire pipeline at the full resolution of the input data. **Figure 3-1** provides a visual representation of the segmentation process.

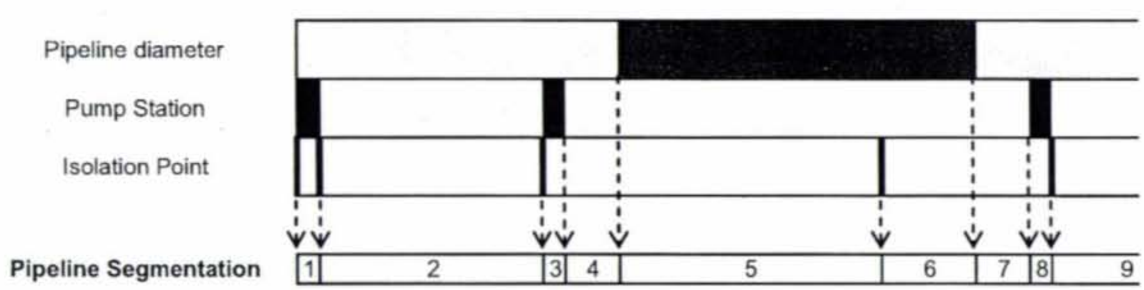


Figure 3-1 Segmentation Process Diagram

Non-discrete (or nearly continuous) risk characterization parameters are not suitable inputs to a segmentation process. These parameters have either a continuously varying value or a large number of values along the length of the pipeline, and would result in a very large number of segments. Instead of using these as inputs to the process, a single value for each parameter was established for each segment after segmentation is complete. The segment value was assigned by analyzing the range of values for a given parameter within a given segment, and assigning either the maximum, minimum, count, or average to the entire segment. This resulted in a representative but conservative value being applied to each segment.

The values for such non-segmentation parameters were assigned as follows (**Table 3-4**):

Table 3-4 Non-Segmentation Parameter Values

Parameter	Related cause	Discussion
Depth of cover	Excavation damage Washout Vehicle impact Aircraft impact Train derailment	Depth of cover is currently assigned a constant value of 4 ft for the entire pipeline. When additional detailed data are available, the minimum depth of cover between the start and end mileposts of each segment will be applied to the entire segment, since this will provide the best reasonable conservative estimate as an input to excavation leak frequency.
Pipeline internal pressure	NA (volume related)	The maximum pipeline internal pressure between the start and end mileposts of each segment will be applied to the entire segment, since this will give the most conservative estimate of before isolation release rate.
Pipeline elevation	NA (volume related)	The minimum pipeline elevation between the start and end mileposts of each segment will be applied to the entire segment, since this will give the most conservative estimates of before isolation and after isolation release rates.

4.0 Base Frequencies and Modification Factors

The frequency of an event is the expected number of times per length of pipe that an event will occur in a year. As an illustration, the excavation damage frequency for a given segment might be 1.4×10^{-6} based on historical incident data. That frequency represents the number of times that excavation is expected to cause a leak in that segment of the pipe in a year.

For each segment of the pipeline, the frequency of events (and thus possible leaks) was determined by first assessing the frequency of each spill cause individually, distributed among the three hole sizes. These were summed to give the total leak frequency.

$$f = f_{co} + f_{ex} + f_{md} + f_{hy} + f_{fl} + f_{wo} \qquad (4.1) \qquad (4.1)$$

Where:

f = the total leak frequency for a section

f_{co} = leak frequency from corrosion

f_{ex} = leak frequency from excavation

f_{md} = leak frequency from material defects or construction deficiency

f_{hy} = leak frequency from hydraulic event

f_{fl} = leak frequency from flange(s)

f_{wo} = leak frequency from washout event

The individual frequencies were determined by applying modification factors to a base leak frequency for each spill cause. The specific modification factors and hole size distributions are discussed for each of the relevant causes in the following subsections.

4.1.1 Corrosion

This event is defined as the failure of mainline pipe to contain the fluid because of external or internal corrosion-degraded (thinned) pipe. The reliability of the pressure relief system is directly accounted for in the analysis.

DNV proprietary analysis of pipeline leaks suggests a base frequency for corrosion leaks of 6.0×10^{-5} per mile of pipeline per year. DNV considers that because of the expected frequency of smart pigging (at least every seven years, 49 CFR 192.937), the material selection and the comprehensive use of active cathodic protection along the pipeline, engineering judgment warrants a reduction of the base frequency (also see generic analyses in Appendix I). A 50% reduction was applied, resulting in a Keystone Pipeline base frequency for corrosion leaks of

3.0×10^{-5} per mile of pipeline per year. Corrosion is the only spill cause for which the base frequency was changed prior to application of specific modification factors.

Modification factors were applied to the base frequency to represent the following issues:

- Whether the segment was above or belowground
- Initial wall thickness of the segment

f_{co}, the leak frequency from corrosion, was therefore calculated as follows:

$$f_{co} = f_{co}^{'}(M_{Location} M_{Thickness}) \tag{4.2}$$

Where:

$f_{co}^{'}$ = the base frequency of corrosion resulting in a leak (3×10^{-5} per mile year)

$M_{Location}$ = modification factor whether the segment was above or belowground

$M_{Thickness}$ = modification factor for initial wall thickness (set to 1 for Keystone Pipeline)

Above or Belowground Location

The Keystone Pipeline is being designed to consist entirely of belowground pipe except within pump station fence lines. Segments of the pipeline belowground were considered to be more likely to incur external corrosion than aboveground sections.

Based on proprietary analysis of CSFM (1993), CONCAWE (1998), and EGIG (2005) data for external corrosion, DNV developed modification factors for belowground versus aboveground piping. (These datasets were used because as of the date of this report, the more current data sets have not yet been fully analyzed.) The modifying factors shown in **Table 4-1** were used to account for the effect of the location of the pipeline on corrosion leak frequencies.

Table 4-1 Corrosion Location Modifying Factor

Location	Factor
Aboveground	0.2
Belowground	1

Engineering judgment was used to develop the hole size distribution shown in **Table 4-2**, which were applied to leaks resulting from corrosion.

Table 4-2 Hole Size Distribution for Corrosion Leaks

Hole Size	Distribution
Small	87%
Medium	10%
Large	3%

4.1.2 Excavation Damage

This event is defined as a leak resulting from digging equipment striking the pipeline. The base frequency of excavation resulting in a leak is 8.4×10^{-5} per mile of pipeline per year. This value was based on DOT data for "external force" type incidents for natural gas transmission lines. Natural gas pipeline data is appropriate for excavation damage because the product being carried in the pipe has almost no effect on whether excavation damage will occur, or how severe it will be. The frequency is essentially the same for gas and for oil pipelines.

Leaks caused by excavation damage are considered only for belowground sections of the pipeline. Modification factors were applied to the base frequency to represent the following features:

- Depth of cover – assigned as a nominal 4 ft.
- Wall thickness of the pipeline – assumed to be 0.375 in for the 30-inch sections, 0.343 in for the 24-inch, and 0.45 for 36-inch sections of pipe.
- Patrol frequency for the pipeline – assumed to be every two weeks.
- Level of excavation activity – estimated based on the number of road crossings in a given segment, with the numbers of crossings summed for each mile. The values were then compared to the criteria in **Table 4-4** to assign an excavation activity level for the segment. A new segment was created at each milepost where the excavation activity level changed, resulting in a constant activity level for each segment.

f_{ex}, the leak frequency from excavation activity, was therefore calculated as follows:

$$f_{ex} = f_{ex}^{'}(M_{Activity} M_{Depth} M_{Thickness} M_{Patrol}) \quad (4.3)$$

Where:

$f_{ex}^{'}$ = the base frequency of excavation resulting in a leak (8.4×10^{-5} / mile year)

$M_{Activity}$ = modification factor for activity level

M_{Depth} = modification factor for depth of cover

$M_{Thickness}$ = modification factor for wall thickness

M_{Patrol} = modification factor for patrol frequency

The hole size distribution shown in **Table 4-3** was applied for excavation damage leaks. The distribution was based on EGIG (2005) data, details of which can be found in Appendix I.

Table 4-3 Hole Size Distribution for Excavation Damage Leaks

Hole Size	Distribution
Small	25%
Medium	55%
Large	20%

Activity Level

Data for the activity levels along the pipeline were assessed using a system suggested by Muhlbauer (1992). This presented three levels of activity: high, medium and low. DNV also identified areas of no expected activity (Very Low).

Table 4-4 Excavation Activity Categorization

Level	One or more of the following
High	Frequent construction activities High volume of on-call or reconnaissance reports (> 2 / week) Significant roadway culvert risk – summed road crossing value greater than 30 per mile Many other buried utilities nearby
Medium	No routine construction activities that could pose a threat Moderate roadway culvert risk – summed road crossing value greater than 10 to 30 per mile Few on-call or reconnaissance reports (> 2 / week) Few other buried utilities nearby
Low	Virtually no activity reports (< 10 / year) No routine harmless activities in area. Agricultural activities that cannot penetrate to within 1 ft of the pipeline depth may be considered harmless. Very low roadway culvert risk – summed road crossing value greater than 0 to 10 per mile
Very Low	No expected excavation activity, except from maintenance activities Trivial roadway culvert risk – summed road crossing value of 0

The modifying factors shown in **Table 4-5** were used for excavation activity level.

Table 4-5 Excavation Activity Level Modifying Factor

Level of Activity	Factor
High	1.5
Medium	1
Low	0.5
None	0.01

Depth of Cover

Modifying factors shown in **Table 4-6** were used for depth of cover, and a factor of 0.7 was applied to Keystone Pipeline as it will be buried to a minimum of four (4) feet. The modifying factors in the table were based on detailed analysis of the UK Health & Safety Executive (HSE) data (ADL, 1999) and DNV engineering judgment for interpolation. They are discussed further in Appendix I.

Table 4-6 Depth of Cover Modifying Factor

Depth of Cover	Factor
0-3 ft	1
3-6 ft	0.7
6-9 ft	0.5
> 9 ft	0.01

4.1.3 Material Defect or Construction Deficiency

- This event was defined as a break in the mainline pipe caused by material or manufacturing defects, improper welding, or installation errors. Empirical data was used to quantify this value.

- For the period 1988-2000, DOT data shows the base frequency of mechanical or material defects causing leak as 3.81×10^{-5} leaks per mile of pipeline per year (DOT, 2001). This is based upon 34 reported leaks for 893,061 miles of pipeline, utilizing a population of pipelines constructed over a wide range of years. Pipelines built more recently will have been designed and built using more modern codes and standards, and inspected using more advanced techniques. These pipelines, such as Keystone Pipeline, are less likely to suffer leaks as a result of mechanical or material defects in the pipeline.

- Data provided by Kiefner and Trench (2001) supports the conclusion that pipelines constructed after 1970 have a reduced likelihood of construction related defects than those built prior to 1970. This decrease is most significant for longitudinal welds, which are typically performed during manufacturing. A lesser decrease is seen for girth welds, which are typically performed during installation. The following are key inputs to the assessment of material defects or construction deficiencies:

- A 50% reduction in the DOT leak frequency was applied to the entire pipeline because the U.S. portion of the Keystone Pipeline will consist of entirely new materials and be constructed to meet current standards and requirements.

- Material defect or construction deficiencies were considered equally likely to occur anywhere along the pipeline, and no modification factors were applied based on location.

- The hole size distribution is based on European Gas Pipeline Incident Data Group (EGIG) (1993) data, details of which can be found in Appendix I. DNV's analysis of the data resulted in the a hole size distribution (**Table 4-7**) applicable to leaks caused by material defects or construction deficiencies.

Table 4-7 Hole Size Distribution for Material Defect or Construction Deficiency Leaks

Hole Size	Distribution
Small	65%
Medium	25%
Large	10%

Wall Thickness

The modifying factors are normally used for wall thickness. These factors are based on a baseline wall thickness of approximately 0.3 in, and the calculation of the modifying factor for thickness relative to the baseline value from EGIG (2005) data, as detailed in Appendix I. The Keystone Pipeline does not significantly deviate from the baseline thickness, therefore no reduction factor is applied (a significant deviation would be a difference in wall thickness greater than 0.5 inches).

Table 4-8 Wall Thickness Modifying Factor

Keystone Pipeline Diameter	Minimum Wall Thickness	Factor
30 inches	0.375 inches	1
24 inches	0.343 inches	1
36 inches	0.450 inches	1

Patrol Frequency

Regular patrols of the pipeline result in earlier identification of excavation activities and improved advance management of such activities. Patrols reduce the likelihood of excavation damage to the pipeline.

Patrol frequency is required by pipeline safety regulations as at least 26 times a year (averaging at two week intervals), but not exceeding intervals of three weeks (49 CFR 195.412). The modifying factors shown in **Table 4-9** were used for patrol frequency. The more frequent the patrols, the more likely the patrol is to observe excavation and assure it is being conducted in a appropriate manner, and the greater benefit the patrolling has in reducing spill risk from excavation. Patrol frequency is expected to be every two weeks for Keystone, with a resultant modifying factor of 1.3.

Table 4-9 Patrol Frequency Modifying Factor

Frequency	Factor
Monthly – Weekly	1.3
Weekly	1
2 times per week	0.8
4 times per week	0.65
Daily	0.5

4.1.4 Hydraulic Event

This event is defined as an overpressure of the pipeline severe enough to cause a leak or rupture of the line. This scenario involves a series of concurrent hardware or human errors and can occur at a limited number of locations.

Overpressure pipe failures can occur through two distinctly different means. Pipe can fail due to overpressurization if the internal pressure surpasses the maximum strength of the pipeline; however, corroded or fatigued pipe will have a reduced strength and may fail at lower pressures. The following scenarios could result in overpressurization:

- Failure of pressure relief system combined with failure of pressure control
- Uncommanded closure of battery limit or block valves
- Failure of RGVs downstream of high elevation areas to fully close during line shutdown. Hydraulic head will create a high pressure at first sealed valve
- Weakening of pipeline at point where slack and tight line meet, due to the impact of pigs, will reduce bursting strength
- Corrosion damage may reduce the bursting strength of the pipeline

The base frequency for hydraulic event leaks is 9.3×10^{-5} per mile of pipeline per year, based on analysis by DNV proprietary analysis of pipeline leaks. A modification factor was applied to the base frequency to represent susceptibility to hydraulic events. f_{hy}, the leak frequency from hydraulic events, was therefore calculated as follows:

$$f_{hy} = f_{co}^{'} M_{Hyd} \tag{4.4}$$

Where:

$f_{hy}^{'}$ = the base frequency of hydraulic events resulting in a leak (9.3×10^{-5} per mile year)

M_{Hyd} = modification factor for susceptibility to hydraulic events

The hole size distribution shown in **Table 4-10** was applied for hydraulic event leaks. This is based on engineering judgment concerning the types of leaks represented.

Table 4-10 Hole Size Distribution for Hydraulic Event Leaks

Hole Size	Distribution
Small	20%
Medium	50%
Large	30%

Hydraulic Event Susceptibility

The modifying factors shown in **Table 4-11** were used for Hydraulic Event Susceptibility. Given the current design phase of the pipeline and the design criteria, it appears that the pipeline warrants a hydraulic susceptibility level of "low", resulting in a modifying factor of 1.

Table 4-11 Hydraulic Event Susceptibility Modifying Factor

Susceptibility		Factor
High	Expected operating pressure >1440 psi	3
Medium	Expected operating pressure between 1040 psi and 1440 psi	1
Low	Expected operating pressure between 520 psi and 1040 psi	0.1
None	Expected operating pressure <520 psi	0

4.1.5 Seismic Events

Keystone is in a very low risk area for seismic activity. It is therefore assumed that leaks caused by seismic events are insignificant.

4.1.6 Washout

This event is defined as failure of the mainline pipe below a river bottom due to severe water erosion. Under severe runoff conditions, pipelines have been known to leak due to the forces applied during pipe displacement. The base frequency of failure (**Table 4-12**) was estimated using proprietary pipeline washout data and engineering judgment.

Table 4-12 Frequency Estimate for Washout Failures

Basis	Source
0.1 pipe exposures / yr assuming 1000 river crossings	Proprietary Data
0.1 failure probability on exposure	Engineering Judgment
= 1×10^{-5} failures / per crossing	

The total pipeline frequency was applied to a stream crossing segment by ratioing the number of stream crossings for the segment to the number for the entire system (806). Each mile of pipeline was assigned a river crossing "value" based on the river type (**Table 4-13**). This was used to segment the pipeline where the density of river crossing varied. Each segment's frequency was then calculated by applying three modification factors to the base frequency:

- River type - National Hydrological Dataset (2006) (F Code) in **Table 4-13**.
- Depth of cover in **Table 4-14**
- Flood risk

Table 4-13 River Crossing Modification Factors

River Type	Modification Factor
River	1
Intermittent/ephemeral stream	0.5
Canal/ditch	0.2
Artificial path or none	0

Table 4-14 Depth of Cover Modifying Factor for Washout Leaks

Depth	Factor
0-10 ft	1
>10 ft	0.5

Table 4-15 Flood Risk Modifying Factor for Washout Leaks

Flood Risk	Factor
0-69	0.5
70-84	0.8
85-100	1

Engineering judgment was used to develop the hole size distribution shown in **Table 4-16**, which were applied to leaks resulting from washout.

Table 4-16 Hole Size Distribution for Washout Leaks

Hole Size	Distribution
Small	90%
Medium	9.9%
Large	0.1%

5.0 Realistic Maximum Spill Volume

The second phase of this assessment calculated the quantity of crude oil that could be lost from each segment of the pipeline. The quantity of material released during a spill is dependent upon the following parameters:

1. Time until leak is detected, verified and pipeline isolated
2. Initial leak rate, under pipeline pressure
3. Quantity of material in isolated section of pipeline
4. Quantity of trapped volume due to changes in pipeline elevation, as described in section 5.3.
5. Leak rate after isolation, driven by hydrostatic head in the pipeline

And, depending on whether containment of the leak source is being considered:

6. Time to effectively contain the leak source (via clamping or some other method)

Detection time is the time required for a potential leak to be identified as such. Verification time is the time required for an operator to confirm that a leak is occurring and decide to take action. Isolation time is the time required from completed leak verification to closure of the remote block valve(s) (RBV) and a relevant downstream check valve, if applicable. Effective valve closure limits the spill volume to the amount trapped between the valves.

A remote block valve is a block valve that stops oil flow in both directions when given a command from a remote location, such as an operations center (or locally if such an option is provided in the design). RBV are located at every pump station and at every major river crossing.

A check valve allows one-way flow only and prevents the reverse flow of oil. Check valves are designed to be held open by flowing oil and to drop closed automatically and nearly effective immediately when oil flow stops or is reversed. Check valves are located on the downstream side of major river crossing along the pipeline. Co-located with each check valve at river crossings, there is also a manual valve.

Prior to valve closure, the leak rate from the pipe ("initial leak rate") is estimated to be the rate that oil would flow out of the hole size being evaluated assuming that the mainline pumps continue to operate. After valve closure, the volume trapped between the upstream RBV and the downstream checkvalve ("isolated section volume") is the maximum that could practically be released. For every potential leak location, the relevant RBV are identified and valve closure times applied based on the values in the tables presented in following subsections.

Actual spill volumes are expected to be significantly less than the potential drain down volume. Accounting for procedures to reduce spill volume, such as depressurization and drain down, may significantly reduce the predicted spill volumes estimated for the Keystone Pipeline.

5.1 Detection, Verification, Response and Isolation

The time required to detect and verify a spill is dependent on the leak detection mechanism that would alert an operator, related to leak rate. The type of cause affects the estimate of times to detect and verify. If the spill cause is such that an individual would be expected to be present and report the leak immediately, the detection/verification times would be different than if the leak detection system was the only means of identifying a spill.

For the purpose of discussion, a cause is called, "reported" if a person is expected to be present at the scene, and very likely to observe the leak and call it in within a short timeframe (regardless of whether the leak is detectable by the leak detection system). An example is excavation damage. Such an event would likely be observed at the time of the incident, and a phone call would be placed to report that a pipeline had been hit during excavation activities. The two reported causes are:

- Excavation damage
- Hydraulic (pressure surge) event

For reported causes, it is assumed that the leak is observed, reported, verified, and valves instructed to close in the times indicated in **Table 5-1**. The listed response times are based on operational and engineering experience, while the valve closure time is manufacturer data. Very small hole leaks may require a few minutes before a leak is apparent, hence the longer observation, reporting, and verification time. Medium hole leaks would be immediately apparent, and would require effective communication to the control center to initiate valve closure. Large hole leaks would be detected in the control center within 9 minutes, regardless of additional reporting avenues.

Table 5-1 Time from Leak Start to Closure of RGVs for Reported Causes

Hole size	Response Time	Valve Closure
Small	30 minutes	3 minutes
Medium	15 minutes	3 minutes
Large	9 minutes	3 minutes

Non-reported causes are expected to occur without any person present to witness and report the event; thus, the leak detection system and surveillance is assumed to be the only means of leak detection for these causes. For example, a corrosion leak is not normally visible to any individuals who pass by, and would have to be detected via the Keystone systems designed for that purpose. The non-reported causes are:

- Material defect or construction deficiency
- Corrosion (external or internal)
- Flange, seal, and fitting leak
- Washout

The estimated times to detect, verify, initiate valve closure, and complete valve closure (isolation) for non-reported causes are provided in **Table 5-2**. The listed times are based on the current leak detection system model design and leak detection system response time. For large leaks, the time for detection system response is independent of whether the leak is above or belowground. Small leaks belowground (necessarily detected by surveillance) may take significantly longer to detect than small leaks aboveground.

Table 5-2 Time from Leak Start to Closure of RGVs for Non-Reported Causes

Leak Rate (as percentage of throughput)	Detection and Verification	Isolation
	Belowground Pipe	Time for RBV to Close
Less than 1.5%	90 days	3 minutes
5%	90 minutes	3 minutes
53%	5 minutes	3 minutes

For leak rates between those presented in the above tables, times were interpolated using a logarithmic straight line fit. This gave the profile in **Figure 5-1** for detection time versus leak rate.

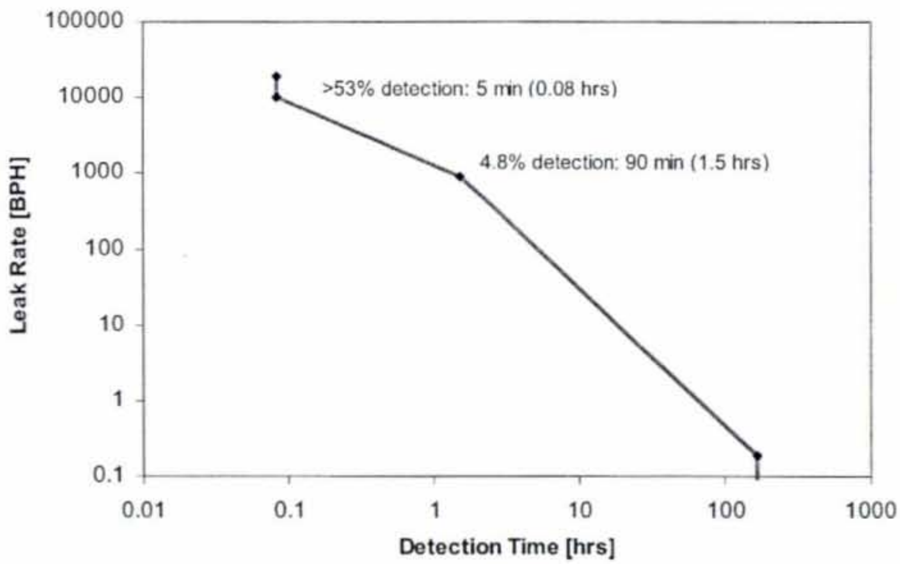


Figure 5-1 Leak Detection & Verification Times

This study assumes that all valves close on demand (zero percent failure rate). The zero failure rate is assumed because of the very low likelihood of a leak concurrent with a valve failure at a critical relevant location. However, a relevant valve failure concurrent with a leak could result in a spill volume greater than estimated in this study; any failure resulting in a delay in leak isolation would increase the spill volume. Such possible complications in leak isolation are:

- RBV fails to close on command
- Check valve fails to drop on loss of flow
- Controller for pump station isolation valves is damaged

5.2 Initial Leak Rate

Standard hole discharge rates were used based on the representative hole size and the operating pressure of the given segment of the pipeline. This formula is given by:

$$Q_D = C_d A \sqrt{\frac{2\Delta P}{\rho}}$$

where:

Q_D = liquid discharge rate (m^3/s)

C_d = discharge coefficient, set to 0.61

A = hole cross-sectional area (m^2)

ΔP = driving pressure for the leak (Pa)

ρ = density (kg/m^3), 938 kg/m^3 for Keystone

During the initial phase of the leak before the valves close, the driving pressure is based on line pressure at the point of the leak.

5.3 Isolated Section Volumes

Once flow through the pipeline is stopped by shut down of pump stations and closure of RBV, material can still leak from the pipeline via gravitational effects. RBV will stop material flowing in from sections upstream and downstream of the isolation valves, and check valves will stop material flowing back from sections downstream. However, material upstream will be able to flow through check valves, since this is the normal direction of flow.

It was assumed that gravitational effects were the sole mechanism for release after isolation. Siphoning effects, draindown procedures, and line depressurization were not considered. Therefore, the sections of the pipeline that were able to contribute to the spill quantity were those satisfying the following criteria **(Figure 5-2)**:

1. Located between the same two remote block valves as the leak point
2. No further downstream of the leak point than the first downstream check valve
3. At a higher elevation than the leak point
4. At a higher elevation than any other point located on the same side of the leak, and closer the leak point

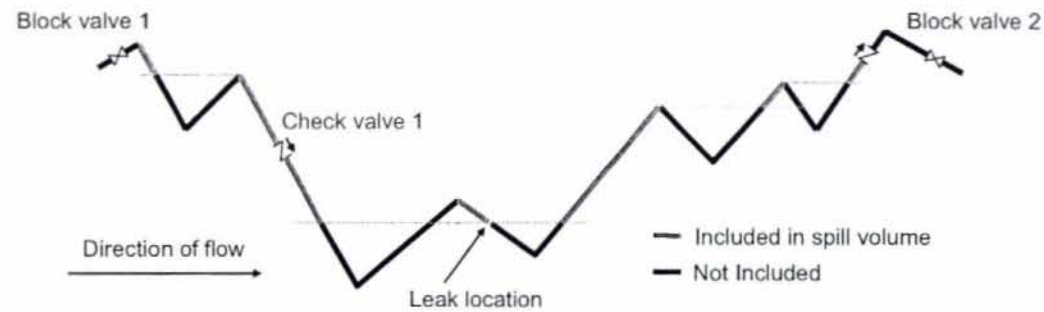


Figure 5-2 Isolated Section Volumes

5.4 Leak Rate After Isolation

In the static phase of the leak, the driving pressure is based on the highest point above the leak, as in isolated volumes, accounting for a closed valve or a peak in the line. For the static phase, the height differential was used to calculate the discharge rate. This formula is given by:

$$Q_S = C_d A \sqrt{2g\Delta h}$$

where:

C_d	=	discharge coefficient, set to 0.61
A	=	hole cross-sectional area (m^2)
g	=	gravitational constant 9.81 (m/s^2)
Δh	=	differential height of crude in line (m)

5.5 Source Control Time

It is assumed that following leak detection, the pipeline will be shut down by means of stopping the pumps and closing the RBV. For small leaks it is also possible to limit the drainage by various source control measures (clamping, gel block). As an initial assumption, these means have been assumed to be in place within four hours throughout the pipeline. Therefore the maximum gravity assisted leak is limited to fours hours for medium and small hole sizes.

5.6 Calculation of Spill Volumes

Spill volumes were calculated based on the leak rate and time to isolate. It is important to note that this assessment adopts a conservative approach to estimating spill volumes. The method does not take credit for any reduction in spill volume due to additional actions to control the source aside from shutdown, RBV closure, and plugging. Thus, procedures to reduce spill volume involving depressurization and draindown are not estimated or included. Such procedures would likely be effective for only small and perhaps medium holes.

6.0 Summary and Conclusions

6.1 Calculated Likelihood of Leaks

The risk analysis of the Keystone Pipeline focused on the likelihood of leaks over the entire pipeline during its lifetime. The base frequencies discussed in Section 4.0 were adapted to each segment via application of modification factors. The resulting leak frequencies were summed to provide an average annual leak frequency for the pipeline lifetime.

For the four cases studied, only one case incorporated both the Keystone Mainline and the Cushing Extension, the 591,000 bpd Diluted Bitumen Case. For this case, the likelihood of a leak greater than 50 barrels anywhere along the pipeline is predicted to be about 0.15 per year, or once every 7 years. In the three other cases, where only the Keystone Mainline is included, the likelihood of a leak greater than 50 bbl anywhere along the pipeline is predicted to be about 0.09 per year, or once every 11 years.

The calculated likelihood of spills less than 50 bbl is considerably less than practical experience would dictate. This is primarily the result of historical reporting requirements, as spills of less than 50 bbl were not required to be reported to the DOT within the historical data set. The current requirement of reporting all spills above 5 bbl is therefore not represented in the dataset used in this analysis.

The overall contribution of various causes (as discussed in Section 4.0) to leaks along the pipeline is shown in **Table 6-1**, **Table 6-2**, and **Figure 6-1**. For each cause, the percent contribution is the total frequency for that cause divided by the total leak frequency for all causes.

Table 6-1 Predicted Pipeline Average Leak Frequency, Synthetic Crude

Cause	435,000 bpd Mainline Only		591,000 bpd Mainline Only	
	Percent Contribution	Frequency (per year)	Percent Contribution	Frequency (per year)
Excavation	39%	0.035	37%	0.035
Corrosion	35%	0.032	34%	0.032
Hydraulic Event	0%	0.000	4%	0.004
Mechanical Defect	23%	0.021	22%	0.021
Washout	2%	0.002	2%	0.002
Total	**100%**	**0.090**	**100%**	**0.093**

Table 6-2 Predicted Pipeline Average Leak Frequency, Diluted Bitumen

Cause	435,000 bpd Mainline Only		591,000 bpd Mainline and Cushing Extension	
	Percent Contribution	Frequency (per year)	Percent Contribution	Frequency (per year)
Excavation	37%	0.035	30%	0.045
Corrosion	34%	0.032	27%	0.040
Hydraulic Event	5%	0.005	24%	0.036
Mechanical Defect	22%	0.021	17%	0.026
Washout	2%	0.002	2%	0.003
Total	**100%**	**0.094**	**100%**	**0.151**

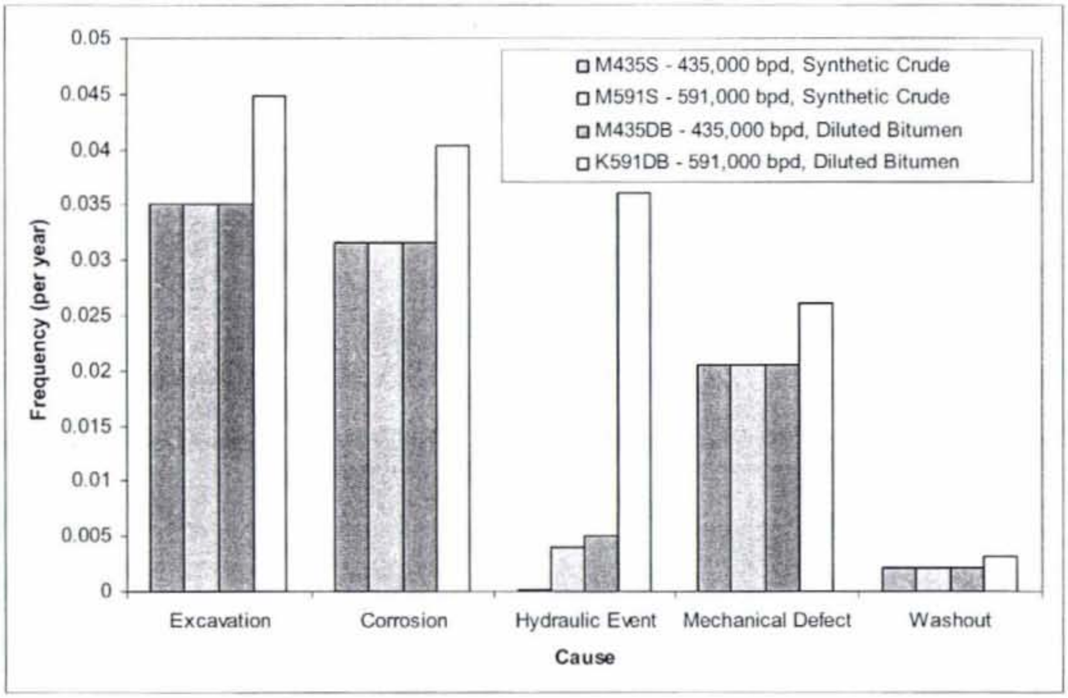


Figure 6-1 Distribution of Pipeline Leak Causes

For all cases, the greatest contributing cause is excavation and the second greatest is corrosion. For the 591,000 bpd Diluted Bitumen case, the next greatest contributing cause is hydraulic events, followed by mechanical defects. For the other cases, the next greatest contributing cause is mechanical defects, followed by hydraulic events. The differences in hydraulic event contribution from the cases are a direct effect of the hydraulic profile and the method used to differentiate higher risk segments regarding hydraulic risk. The 591,000 bpd Diluted Bitumen (K591DB) case is assumed to operate under higher pressure than the 435,000 bpd Keystone Mainline (M435S) case. As a result, the K591DB case is in general closer to the MAOP, which from a risk perspective increases susceptibility to over pressure events.

6.2 Hole Size Distribution

Considering both the Keystone Mainline and the Cushing Extension, approximately 49% of the spills would be from small holes (pinholes), 36% would be from medium sized holes (2 in), and 16% would be from large holes (10 in or greater). When only considering the Keystone Mainline, approximately 57% of the spills would be from small holes (pinholes), 32% would be from medium sized holes (2 in), and 12% would be from large holes (10 in or greater).

Table 6-3 Hole Size Distribution

Case	Small (0.06 inches)	Medium (2 inches)	Large (>10 inches)
M435S	58%	31%	11%
M591S	56%	32%	12%
M435DB	56%	32%	12%
K591DB	49%	36%	16%

6.3 Summary of Frequency-Volume Results

In general, reported incidents over decades provide a good basis for estimating spill volumes and frequencies for new pipelines. However, there are some key weaknesses in this use of such data:

1. Small volume spills are significantly underreported, particularly those less than the reportable quantity.
2. Extremely infrequent events may not have occurred during the period of data collection of incidents.

Figure 6-2 to **Figure 6-5** provide a view of the total frequency of spill volumes.

The necessary assumptions and the current design phase of the pipeline required conservative assumptions to be applied, with the result no identified spill volumes between 200 bbl and 1000 bbl for some of the cases. The results should not be interpreted to mean that no spills are likely to occur in that category, but rather, several input assumptions were of a nature that detail in resolution (such as the difference between categories of lesser volume spills and detection time) is unavailable in the output. The category likely falls within the uncertainty of the analysis for a pipeline in the design phase.

The spill volume risk analysis shows the highest frequency for the 50 to 200 bbl category of spill volumes. Spill volumes in this category are driven by leaks that take a long time to detect, as well as medium leaks. Spill volumes between 1000 bbl and 10,000 bbl consist nearly entirely of medium hole leaks, and spills greater than 10,000 bbl consist of large hole size leaks.

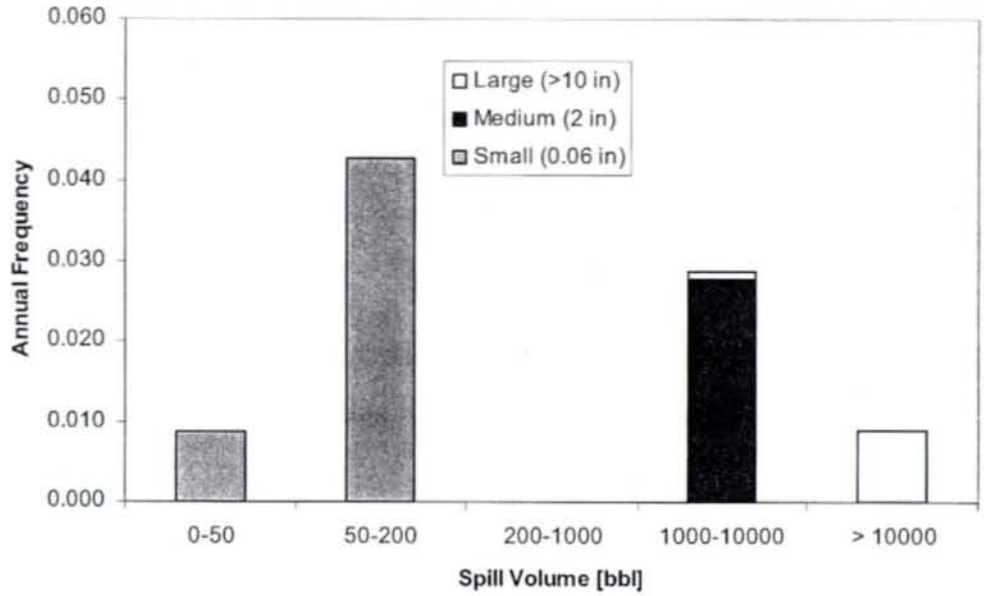


Figure 6-2 Frequency of Spill Volumes by Category (435,000 bpd, Synthetic Crude)

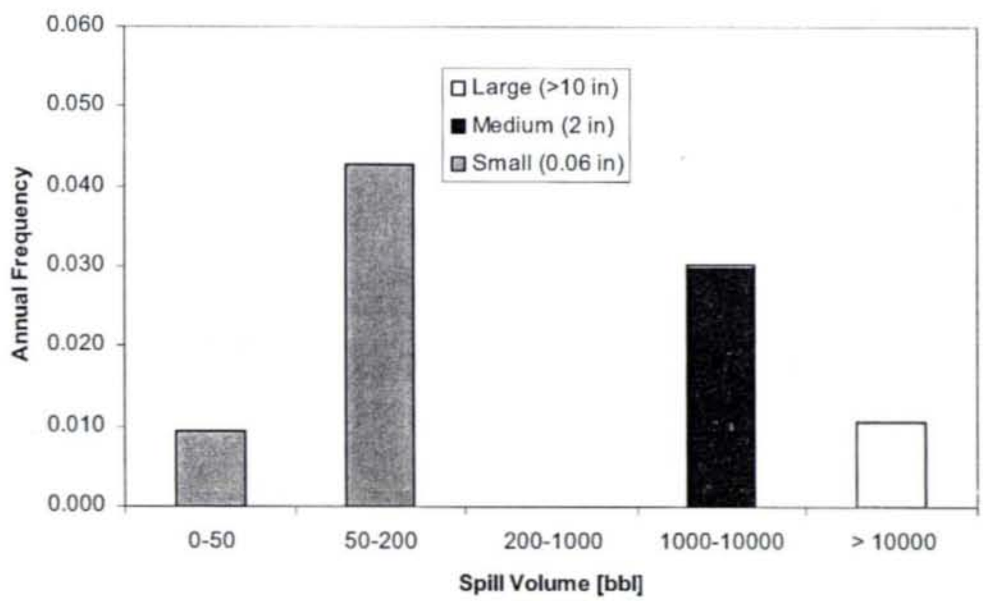


Figure 6-3 Frequency of Spill Volumes by Category (591,000 bpd, Synthetic Crude)

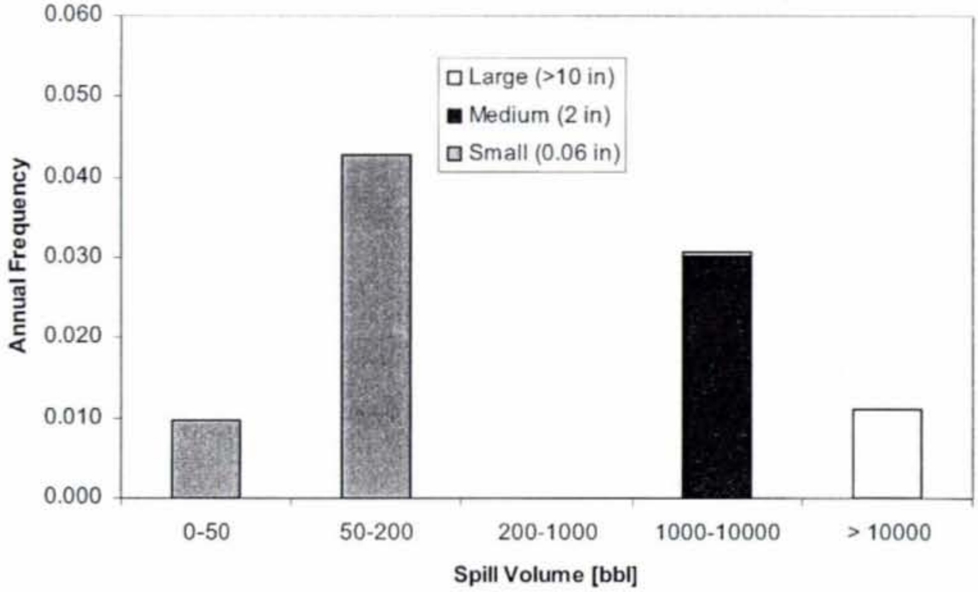


Figure 6-4 Frequency of Spill Volumes by Category (435,000 bpd, Diluted Bitumen)

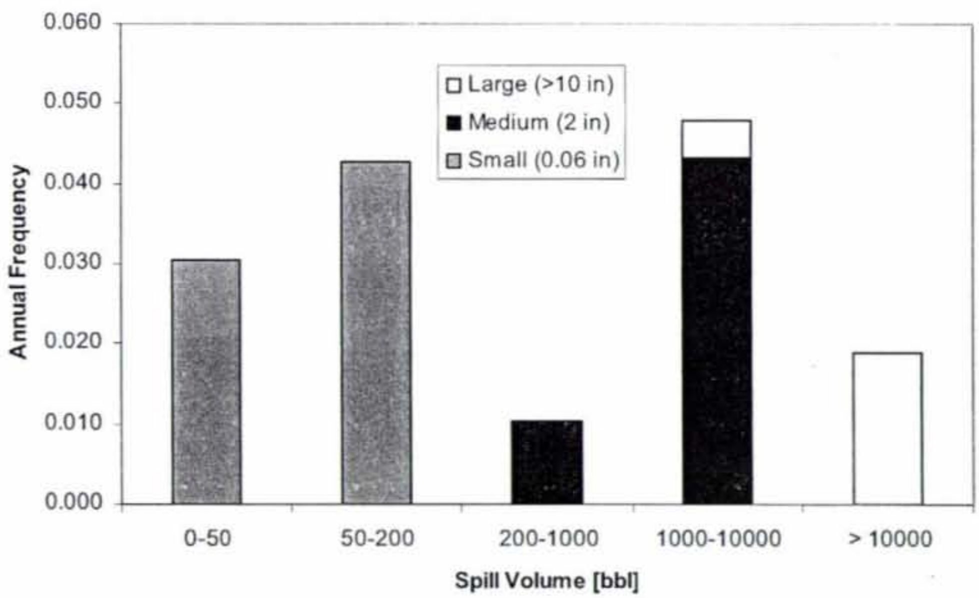


Figure 6-5 Frequency of Spill Volumes by Category (591,000 bpd, Diluted Bitumen)

Figure 6-6 provides a view of the spill size distribution. The cases are described in three categories:

1. Greater throughput, greater pressure, represented by the K591DB case
2. Medium pressure, represented by the M591S and M435DB cases
3. Lesser throughput, lesser pressure, represented by the M435S case

For category 1, 9% of leaks result in spills greater than 20,000 bbl and only 0.7% of the leaks estimated in this study result in spills greater than 30,000 bbl.

For category 2, 4.5% of leaks result in spills greater than 20,000 bbl and only 0.25% of the leaks estimated in this study result in spills greater than 30,000 bbl.

For category 3, 1.5% of leaks result in spills greater than 20,000 bbl and only 0.15% of the leaks estimated in this study result in spills greater than 30,000 bbl.

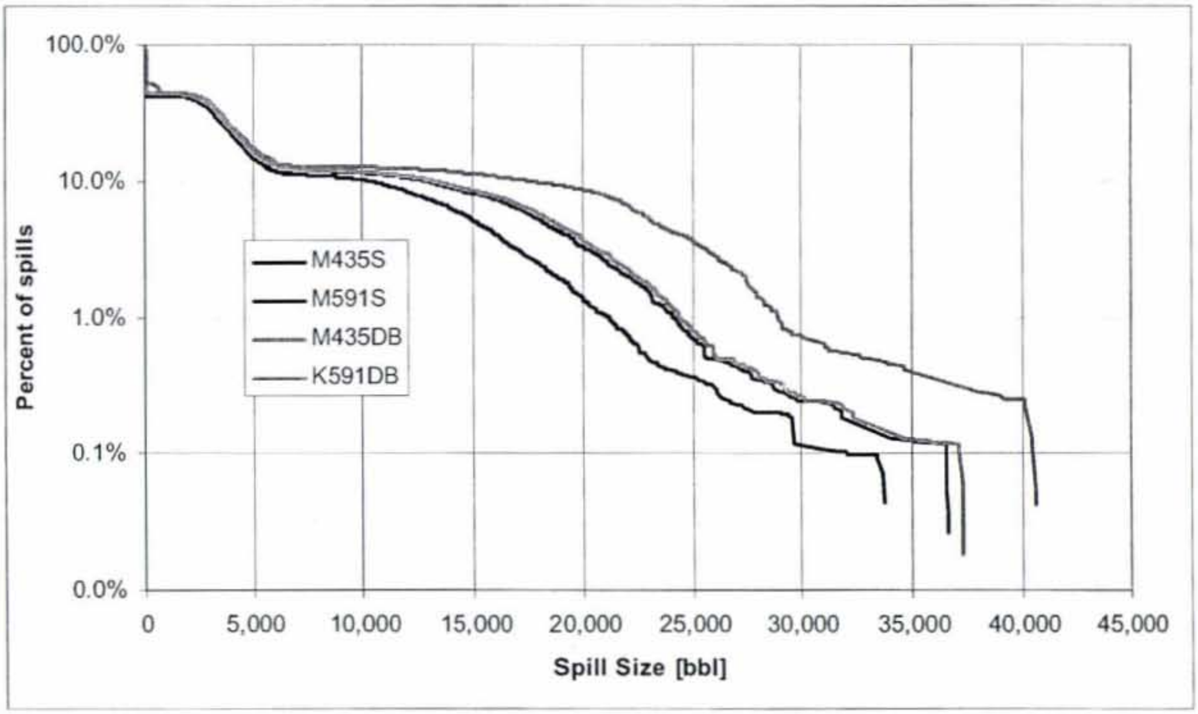


Figure 6-6 Cumulative Spill Volume

The four cases represent the range of expected spills from Keystone Pipeline. However, spill frequency alone does not provide an accurate picture of risk from Keystone. Evaluation of risk requires assessing frequency and consequence together rather than separately, because the worst risk scenario is often not the greatest volume release -- a large volume release often is associated with a small frequencies.

To identify the worst-case pairing on frequency and volume (a screening level indicator of risk), the frequency and volume were multiplied and summed per segment for the K591DB case, providing a "risk" number with which to compare the segments of Keystone.

Table 6-4 Largest Spill Volume Segments

Section of Pipeline	Segment Length [mi]	Annual Volume [bbl]	% of Total Annual Volume	Case
Mainline	6.71	11.542	1.9%	K591DB
Mainline	5.16	10.201	1.6%	K591DB
Mainline	6.00	8.700	1.4%	K591DB
Mainline	7.49	8.318	1.3%	K591DB
Mainline	7.00	7.910	1.3%	K591DB
Mainline	5.98	7.779	1.3%	K591DB
Mainline	3.25	6.471	1.0%	K591DB
Mainline	4.29	5.766	0.9%	K591DB
Mainline	4.00	5.311	0.9%	K591DB
Mainline	3.82	5.297	0.9%	K591DB

Keystone has prepared a consequence study that estimates the severity of potential spills from Keystone (paired with their respective frequencies) and identifies those segments posing the greatest risk to the environment. Potential preventive measures will then be evaluated to determine which are the most effective in reducing environmental risk.

This frequency-volume study provides Keystone with a detailed database of failure causes, corresponding likelihood and consequence (in terms of volume released) for the Keystone Pipeline, divided into the smallest relevant subdivisions. Keystone is using the associated database to identify pipeline segments posing the greatest risk (in terms of frequency and volume). This information, taken with fate and transport modeling, is being used to determine where and which additional mitigation measures are appropriate.

6.4 Uncertainties

The data used in this analysis is based on crude transportation pipeline and on gas pipeline data where applicable (external causes). The Diluted Bitumen case has been estimated assuming the failure causes are identical to crude oil. The diluent used, potential presence of oxygen in the diluent, presence of particles in the product, and flow velocity in the pipeline are important factors affecting whether corrosion will be increased or decreased compared to the average pipeline.

The above can be mitigated if necessary, but this study does not assess the effect of diluted bitumen on failure frequencies.

6.5 Comparison with Generic Pipeline Leak Frequency

Table 6-5 Leak Volume Summary

Case	Leak Volume (per mile per year)
M435S	0.24
M591S	0.29
M435DB	0.30
K591DB	0.45

In summary, the average leak volume per mile for the Keystone Pipeline is estimated in the range of 0.24 bbl to 0.45 bbl per mile per year (**Table 6-5**). For purposes of comparison, pipelines in the U.S. had an average leak frequency of 0.49 bbl per pipeline mile per year during the period 1992 to 2003 (OPS 2006). Thus, the Keystone Pipeline is estimated as better than average regarding oil spill frequency.

7.0 References

DNV 2006 Frequency-Volume Study of Keystone Pipeline, Report no. 70015849-2, Rev 2, 01 June 2006

OPS 2006 http://ops.dot.gov/stats/IA98.htm

CONFIDENTIAL

DNV Energy

DNV Energy is a leading professional service provider in safeguarding and improving business performance, assisting energy companies along the entire value chain from concept selection through exploration, production, transportation, refining and distribution. Our broad expertise covers Asset Risk & Operations Management, Enterprise Risk Management; IT Risk Management; Offshore Classification; Safety, Health and Environmental Risk Management; Technology Qualification; and Verification

REGIONAL HEAD OFFICES:

DNV ENERGY
Americas and West Africa
Rua Sete de Setembro
111/12 Floor
20050006 Rio de Janeiro
Brazil
Phone: +55 21 2517 7232

DNV ENERGY
Asia and Middle East
24th Floor, Menara Weld
76, Jalan Raja Chulan
50200 Kuala Lumpur
Malaysia
Phone: +603 2050 2888

DNV ENERGY
Europe and North Africa
Palace House
3 Cathedral Street
London SE1 9DE
United Kingdom
Phone: +44 20 7357 6080

DNV ENERGY
Nordic and Eurasia
Veritasveien 1
N-1322 Hovik
Norway
Phone: +47 67 57 99 00

DNV ENERGY
Offshore Class and Inspection
Veritasveien 1
N-1322 Hovik
Norway
Phone: +47 67 57 99 00

DNV ENERGY
Cleaner Energy & Utilities
Veritasveien 1
N-1322 Hovik
Norway
Phone: +47 67 57 99 00

MANAGING RISK DNV

Appendix I:
Generic Failure Rate Data

contents:

I GENERIC FAILURE RATE DATA

I.1 Introduction

Generic failures rates are used in this study to assess spill frequencies for the Keystone Pipeline. This is most specific to the cross-country pipeline portion. The generic failure rate data is separated into cross-country pipeline data and pump station equipment data.

I.2 Cross-Country Pipelines

I.2.1 Introduction

In performing a risk assessment, it is useful to compare the failure history of the system at hand to other sources of information. First, one can gauge whether the pipeline operator is performing up to industry standards. Second, external data sources provide a more statistically significant basis for predicting pipeline failure rates, since most individual pipelines do not have a sufficient operating history to develop statistical significance. However, it is important to select the source of data that is most relevant to the operating conditions and leak reporting standards of the pipeline under review.

There are many sources of pipeline failure rate data. The only source of leak frequencies that clearly defines hole sizes was collected by the European Gas Pipeline Incident Data Group (EGIG, 1993), which covered gas transmission pipelines in Western Europe from 1970 to 1992. This data set also provides good information regarding incident causes.

Probably the largest and best known source of U.S. data is from the U.S. Department of Transportation (DOT) Office of Pipeline Safety, which collects data for both hazardous liquids pipelines and natural gas transmission pipelines. Another good source of U.S. data is the California Pipeline Study published by the California State Fire Marshal (CSFM, 1993). This study had no lower threshold for reporting and collected data regarding several design and operating variables.

Based on comparisons of different sources, the uncertainty in these values is estimated to be up to a factor of three higher for liquid pipelines and a factor of three lower for gas pipelines.

I.2.2 Failure Experience

Major accidents involving cross-country pipelines included:

I.2.2.1 Natural Gas & LPG Spills

- NGL pipeline leak and fire, Austin, Texas, USA, 22 February 1973. A 900-tonne leak of NGL occurred from a 10 inch pipeline. Vehicles stalled inside the cloud and eventually ignited it, killing eight people (Lees 2005 case history A62).
- LPG pipeline leak and fire, Donnellson, Iowa, USA, 4 August 1978. A leak of 435 tonnes occurred from a 16-year-old 8 inch propane pipeline in a rural area. A dent while the pipeline was being constructed and stresses while it was being lowered three months prior to the incident resulted in a 33 inch long split forming. The gas ignited, forming a fireball of 1,000 foot radius, killing three people (Lees 2005 case history A91).
- LPG pipeline leak and fire, Ufa, USSR, 4 June 1989. A leak occurred in an LPG pipeline in a wooded valley, two kilometers from the Trans-Siberian Railway. The operator responded by increasing the pressure. This created a vapor cloud 8 kilometers long. Some hours later, two

trains traveling in opposite directions entered the cloud and ignited it, causing explosions and a fire and derailing the trains, causing an estimated 462 fatalities (Lees 2005 case history A127).

- Natural gas pipeline leak and fire, Caracas, Venezuela, 28 September 1993. An excavator laying telephone cables beside a highway ruptured a gas pipeline, which ignited killing 51 motorists, injuring 41 and destroying 20 vehicles (DNV Technica 1995c K5429).
- Natural gas pipeline leak and fire, Carlsbad, New Mexico, 19 August 2000. The probable cause of this accident was a significant reduction in pipe wall thickness due to severe internal corrosion which had occurred because EPNG's corrosion control program failed to prevent, detect, or control internal corrosion within the company's pipeline. The released gas ignited and burned for 55 minutes. Twelve persons who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed and their three vehicles destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were extensively damaged (National Transportation Safety Board, 2003).

I.2.2.2 Gasoline Spills

- Gasoline pipeline leak and fire, Los Angeles, California, USA, 16 June 1976. An 8 inch pipeline in an urban area was punctured by road excavation equipment, causing a 120 x 60 mm hole. The explosion and fire caused eight fatalities, 14 injuries and damaged 16 buildings (Mather and Lines, 1999).
- Gasoline pipeline leak and fire, Bayamon, Puerto Rico, 30 January 1980. A leak of 270 tonnes occurred from a 250 x 150 millimeter hole in a gasoline pipeline caused by a bulldozer during maintenance work on a nearby water pipe. After one and one-half hours, the leak ignited, killing a person who was collecting petrol for personal use and causing damage up to three kilometers away (Mather and Lines, 1999).
- Gasoline pipeline leak and fire, Cubatao, Brazil, 24 February 1984. A leak of 700 tonnes occurred from a 30-year old gasoline pipeline, around which a shanty town had been built. The spill spread along the ground and ignited after two minutes. It was 45 minutes before fire fighters arrived, and by then most of the 2,500 dwellings in the shanty town had been destroyed, killing 508 people (Lees 2005 case history A108).
- Gasoline pipeline leak and fire, San Bernardino, California, USA, 25 May 1989. A 14 inch gasoline pipeline ruptured two weeks after being struck by a derailed freight train. The wreck removal operations may have caused an undetected crack in the pipeline. The rupture was 28 inches long (2x diameter) and 4 inches wide, and sprayed gasoline into a residential area, which ignited causing two fatalities and 31 injuries. A total of 1000 tonnes was spilled due to failure of untested check valves (Mather and Lines, 1999).
- Gasoline pipeline leak and explosion, Guadalajara, Mexico, 22 April 1992. Gasoline leaking through a corrosion hole over several weeks migrated into the sewer system under an urban area. This caused a series of explosions that caused 252 fatalities and destroyed a 20 block area of the city (Mather and Lines, 1999).
- Gasoline pipeline leak and fire, Uong Bi, Vietnam, 2 November 1993. Gasoline leaking from a pipeline in a rural area was ignited, causing 47 fatalities among people collecting it for personal use (Mather and Lines, 1999).
- Gasoline pipeline rupture and fire, Bellingham, Washington, 10 June 1999. A 16-inch-diameter steel pipeline owned by Olympic Pipe Line Company ruptured and released about 237,000 gallons of gasoline into a creek that flowed through Whatcom Falls Park. About 1 1/2

hours after the rupture, the gasoline ignited and burned approximately 1 1/2 miles along the creek. Two 10-year-old boys and an 18-year-old young man died as a result of the accident. Eight additional injuries were documented. A single-family residence and the city of Bellingham's water treatment plant were severely damaged (National Transportation Safety Board, 1999).

- Gasoline pipeline leak, El Paso, Texas, 28 May 2005. An unknown failure of a 12-inch gasoline pipeline resulted in a release of an undetermined volume of gasoline. A respondent discovered a 25-square foot area saturated with gasoline. No fires, injuries, or fatalities were reported in connection with the accident. (Office of Pipeline Safety, 2005)

I.2.2.3 Crude Oil Spills

- Crude oil pipeline punctured, Near Fairbanks Alaska, February 1978. An unknown party bombed the pipeline with plastic explosives at Steel Creek near Fairbanks. As a result, 16,000-barrels (672,000-gallons) were spilled (Rocky Mountain Institute, 2001).
- Crude oil pipeline punctured, Near Fairbanks Alaska, 4 October 2001. An intoxicated 37-year-old local resident, Daniel Lewis, shut down TAPS near its midpoint with a single 0.338-caliber rifle bullet. It punctured the half-inch wall of the 48" pipe (and the surrounding insulation and galvanized sleeve). Approximately 6,800 barrels (285,600 gallons) of crude oil spewed out in a 75-foot, up to 140-gallon-a-minute stream into several acres of forest from the roughly 20,000 barrels (840,000 gallons) of 525-psi oil in the affected section (Rocky Mountain Institute, 2001).
- Crude oil pipeline leak, North Slope, Alaska, 2 March 2006. A leak occurred in a section of pipe built in the late 1970's, depositing up to 267,000 gallons over two acres in the Prudhoe Bay production facilities. Corrosion is initially thought to be the cause of the hole in the pipeline. This spill is still under investigation.

I.2.3 Analysis of EGIG Gas Pipeline Data

I.2.3.1 Data Source

EGIG collected pipeline incident data from a group of eight major pipeline operators in Western Europe for the period 1970-92. The database covers onshore gas transmission lines with a design pressure over 15 bar. In 1992, the pipeline network was 93,000 kilometers, with exposure during 1970-92 of 1.5×10^6 kilometer-years.

The analysis included incidents involving unintentional release of gas occurring outside the fences of installations, and excluding valves or parts other than the pipeline itself. These criteria make it ideal for pipeline Quantitative Risk Assessment (QRA).

The available report does not give numbers of incidents, and only gives frequency graphs; the following summary may include errors from scaling off the graphs.

I.2.3.2 Incident Frequency

The overall incident frequency from 1970-92 was 5.8×10^{-4} per kilometer-year. A declining trend was apparent, particularly during the 1970s. The frequency for 1988-92 was 3.8×10^{-4} per kilometer-year. A coarse analysis of a newer revision of the EGIG (2005) suggests that the frequency is lower.

However, a full analysis has not been performed and the frequency of 3.8×10^{-4} is considered the best estimate for this report.

I.2.3.3 Hole Sizes

EGIG categorizes the incidents as:

- Pinhole/cracks - diameter of defect of 20 millimeter or less
- Holes - diameter of defect between 20 millimeter and pipe diameter
- Ruptures - diameter of defect more than pipe diameter

Table I-1 shows the distribution of hole sizes derived from the data.

Table I-1 EGIG Gas Pipeline Hole Type Distribution, 1970-92

Hole Type	Percent
Pinhole/crack	48
Hole	38
Rupture	14
TOTAL	100

In order to obtain frequencies for different hole sizes, DNV assumed that the "pinhole/crack" category includes all leaks over three millimeter equivalent diameter, while the "rupture" category includes leaks over 300 millimeter equivalent diameter. The following hole size function then gives a good fit to the probability distribution, as shown in **Figure I-1**:

$$F(d) = 3.8 \times 10^{-4} \times 1.55\, d^{-0.4} \text{ for } 3 \text{ mm} \le d \le D$$

where:

F(d)	=	frequency of leaks exceeding diameter d (per km-year)
d	=	equivalent diameter of leak (mm)
D	=	diameter of pipeline (mm)

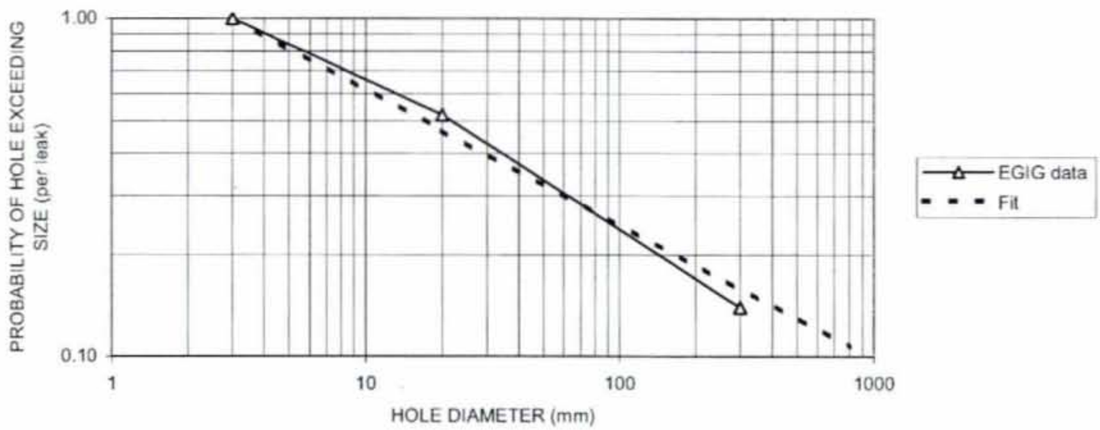


Figure I-1 EGIG Gas Pipeline Hole Size Distribution

I.2.3.4 Incident Causes

Table I-2 summarizes the causes of the incidents in the EGIG data from 1970 to 1996. External interference dominates for both ruptures and medium-sized holes.

Table I-2 Causes of Gas Pipeline Incidents, 1970-96

Cause	% of Pinholes	% of Holes	% of Ruptures	% of Total
External interference	26	77	71	51
Construction/material defect	26	12	12	19
Corrosion	29	0	0	14
Ground movement	3	5	18	6
Hot-tap by error	6	4	0	4
Other/unknown	10	2	0	6
TOTAL	100	100	100	100

I.2.4 Analysis of US Hazardous Liquid Pipeline Data

I.2.4.1 Data Source

The DOT Office of Pipeline Safety collects records of incidents involving hazardous liquid pipelines (crude oil, liquid products and liquefied gases) in the US. The pipeline network amounts to approximately 250,000 kilometer, making it the largest available liquid pipeline incident database. It covers pipeline diameters of 8 inch to 48 inch.

Reportable incidents in the data used for this analysis involved any of the following:

- Explosion or fire
- Loss of more than 50 barrels of hazardous liquid (previous reporting threshold)
- Escape to atmosphere of more than five barrels per day of highly volatile liquid (i.e. liquefied gas)
- Death or injury
- Property damage exceeding $50,000 including cost of clean-up and recovery, value of lost product and damage to property.

There is no information on hole sizes in the incident database. The associated population data gives only the total pipeline length, with no breakdown by diameter or any other attribute. This limits the value of the data for QRA.

I.2.4.2 Spill Frequency

The numbers of incidents and exposure during 1986-98 (DOT, 2005a) are given in **Table I-3**. There is a slight declining trend in incident frequency, but this may be influenced by late reporting at the end of the period. The overall experience of 2,595 incidents in 2 million mile-years is a frequency of 8.1×10^{-4} per kilometer-year.

Table I-3 US Hazardous Liquid Pipeline Spills, 1986-96

Year	No. of Incidents	Fatalities	Injuries	Property Damage ($)	Net Loss (Bbl)	Population (Miles)
1986	209	4	32	16,027,846	219,413	153,462
1987	237	3	20	13,140,434	312,654	152,859
1988	193	2	19	32,414,912	114,251	152,547
1989	163	3	38	8,813,604	121,179	150,488
1990	180	3	7	15,720,422	54,663	149,008
1991	216	0	9	37,788,944	55,774	150,425
1992	212	5	38	38,651,062	68,742	152,595
1993	230	0	10	28,873,651	58,108	165,781
1994	243	1	7	56,453,604	112,348	155,208
1995	188	3	11	32,518,689	53,113	153,566
1996	195	5	13	49,704,731	96,141	154,863
1997	175	0	5	36,565,295	105,952	155,140
1998	154	1	2	57,211,497	51,730	156,753
Totals	2595	30	211	423,884,691	1,424,068	2,002,695

I.2.4.3 Spill Sizes

The gross quantity spilled during 1986-98 of 384,000 m^3 is equivalent to 148 m^3 per spill. **Table I-4** shows the probabilities of spills by range of standard size bands (DOT).

Table I-4 Hazardous Liquid Pipeline Spill Size Probabilities, 1986-98

Spill Size Range (M^3)	Nominal Spill Size (M^3)	Spill Probability
<1	0.3	0.15
1 - 10	3	0.19
11 - 100	30	0.41
101 - 1000	300	0.22
1001 - 10000	3000	0.03
>10000	30000	0.0004
TOTAL		1.00

An average of 41% was recovered, giving a net spill of 87 m^3 per spill. This is sensitive to the materials included, as recovery is not usually relevant for liquefied gases. Kiefner et al (1999) give a breakdown of spills according to whether or not the material was a highly volatile liquid (HVL) for the period 1986-96, from which the average spill sizes in **Table I-5** have been derived.

Table I-5 Hazardous Liquid Pipeline Average Spill Sizes, 1986-96

Pipeline Content	Spills	Average Gross Spill (M^3 Per Spill)	% Recovered	Average Net Spill (M^3 Per Spill)
Non-HVL (crude oil, gasoline, fuel oil etc)	1930	144	53%	68
HVL (liquefied gas)	332	176	0.07%	176
TOTAL	2262	151	43%	86

There is a slight declining trend in quantity spilled. From **Table I-3**, the average net spill for 1996-98 is 77 m^3 per spill, which is 12% lower than the average for 1986-98.

I.2.4.4 Spill Causes

The causes of spills during the period 1986-98 are summarized in **Table I-6**. The large proportion of "other" causes makes this information difficult to use.

Table I-6 Causes of Hazardous Liquid Pipeline Spills, 1986-98

Cause	% of Incidents	% of Gross Spill	Average Gross Spill (M^3 Per Spill)
Corrosion	26	17	101
Failed pipe	6	10	250
Failed weld	5	5	159
Incorrect operation	6	5	116
Malfunction of equipment	5	3	89
Other	26	25	142
Outside force damage	26	35	194
TOTAL	100	100	148

Kiefner et al (1999) give a detailed analysis of causes, as shown in **Table I-7**. Causes are broken down into incidents associated with the pipeline itself, and incidents associated with other facilities such as breakout tanks, pump stations or metering facilities. Non-pipe related incidents accounted for 40% of the total. The DOT data contain a small portion of offshore data (less than 2.5%); the data is therefore assumed to be representative for onshore application.

Table I-7 Causes of Onshore* Hazardous Liquid Pipeline Spills, 1986-96

Cause	% of Incidents
Pipe-related	
Defective girth weld	2.3
Defective pipe	1.8
Defective pipe seam	3.5
Defective repair weld	1.6
External corrosion	19.4
Internal corrosion	9.5
Heavy rains/floods	2.0
Rupture of previously damaged pipe	5.0
Third party	19.9
Total pipe-related	60.5
Non-pipe-related	
Cold weather	1.1
Defective fabrication weld	0.6
Incorrect operation	8.6
Lightning	0.8
Malfunction of control/relief equipment	5.0
Miscellaneous/other	10.8
Ruptured or leaking gasket	5.4
Ruptured or leaking seal or pump packing	2.9
Threads stripped, broken pipe coupling	3.1
Vandalism	1.1
Total non-pipe-related	39.5
Total	100.0

* Offshore population is less than 2.5%

I.2.5 Analysis of US Natural Gas Pipeline Data

I.2.5.1 Data Source

The DOT Office of Pipeline Safety collects records of incidents involving natural gas pipelines (including LNG) in the US. The pipeline network amounts to approximately 525,000 kilometers, making it the largest pipeline incident database.

Reportable incidents involve any of the following:

- Death or injury
- Property damage of $50,000 or more

I.2.5.2 Incident Frequency

The numbers of incidents on transmission lines during 1986-98 (DOT, 2005b) are given in **Table I-8**. The pipeline exposure has been extracted from the DOT annual pipeline population databases where available. The total exposure has been estimated by using the average of the available data for the missing years. The overall experience of 1,068 incidents in 4.2 million mile-years is a frequency of 1.6×10^{-4} per kilometer-year.

Table I-8 US Natural Gas Transmission Pipeline Incidents, 1986-96

Year	No. Of Incidents	Fatalities	Injuries	Property Damage ($M)	Population (Miles)
1986	83	6	20	11.2	
1987	70	0	15	4.7	
1988	89	2	11	9.3	319,811
1989	103	22	28	20.4	324,306
1990	89	0	17	11.3	309,157
1991	71	0	12	11.9	303,171
1992	74	3	15	24.6	312,800
1993	96	1	18	23.0	330,355
1994	81	0	22	45.2	327,799
1995	64	2	10	10.0	327,646
1996	77	1	5	13.1	
1997	73	1	5	12.1	
1998	98	1	11	29.7	326,389
Totals	1068	39	189	226.4	4,162,071

The incidents are broken down according to the part of the system involved, as shown in **Table I-9**. The category "Other" includes offshore risers, storage fields, pig launchers, branch connections and others.

Table I-9 Part of System Involved in Gas Transmission Pipeline Incidents, 1986-96

Part Of System	Incidents	%
Pipeline	831	78
Compressor station	89	8
Regulator metering station	50	5
Other	90	8
Unknown	8	1
TOTAL	1068	100

I.2.5.3 Hole Sizes

The DOT pipeline incident database divides incidents into the following types (**Table I-10**):

- Leaks
- Ruptures, for which a rupture length is given
- Others, such as injury or damage events not involving leaks

The database includes ten incidents with no type allocated. DNV has assumed that the three incidents with a rupture length were ruptures, the four incidents from the body of the pipe without rupture lengths were leaks, and the three incidents from other sources were "Other", i.e. not leaks or ruptures.

The database also divides incidents according to the point where the failure occurred. The category "Other" includes pipeline drips, pig launchers, compressors and appears to include various incorrectly classified valves and fittings.

Table I-10 Incident Type in Gas Transmission Pipeline Incidents, 1986-96

Failure Location	Ruptures	Leaks	Other	Total
Body of pipe	249	231	114	594
Weld	33	51	11	95
Mechanical joint	7	14	19	40
Valve	2	24	13	39
Fitting	5	40	20	65
Other	28	44	140	212
Unknown	1	9	13	23
TOTAL	325	413	330	1068

Figure I-2 gives the distribution of the rupture lengths, expressed as a frequency per pipeline kilometer-year. The rupture length was only recorded for 272 of the 325 ruptures in the database, so the distribution may be a slight underestimate.

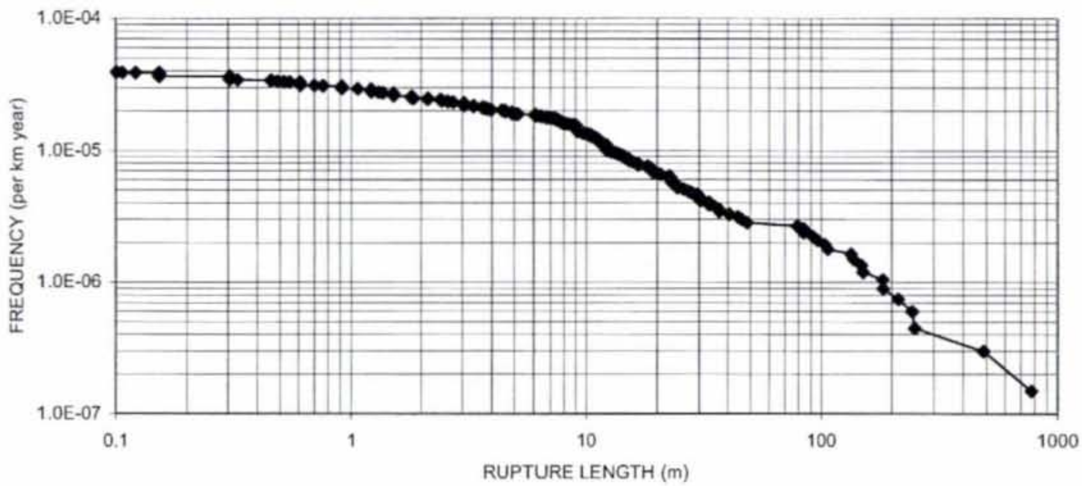


Figure I-2 Gas Transmission Pipeline Rupture Length Distribution, 1986-96

In order to convert the rupture lengths into hole sizes, DNV assumed that the ruptures are diamond-shaped, with a maximum width of 50% of pipeline diameter. Then the hole area is:

$$A = LD/4$$

where:

A	=	hole area (m^2)
L	=	rupture length (m)
D	=	pipeline diameter (m)

Using this approach, approximately 60% of ruptures had areas greater than twice the pipe cross-sectional area. When calculating the release rate in a risk analysis, this is the maximum effective hole size, assuming fluid is able to flow towards the hole from both sides of the rupture. The hole area is therefore limited to a maximum of $2\pi D^2/4$.

The equivalent hole diameter is:

$$d = (4A/\pi)^{0.5}$$

The results are shown in **Figure I-3**, together with the frequency of all leaks and ruptures, assumed to have a diameter of at least three millimeters. Most of the curvature in the results is due to the truncation of hole size at twice the pipe cross-sectional area on different pipe diameters, which are mainly in the range 400 to 1000 millimeters.

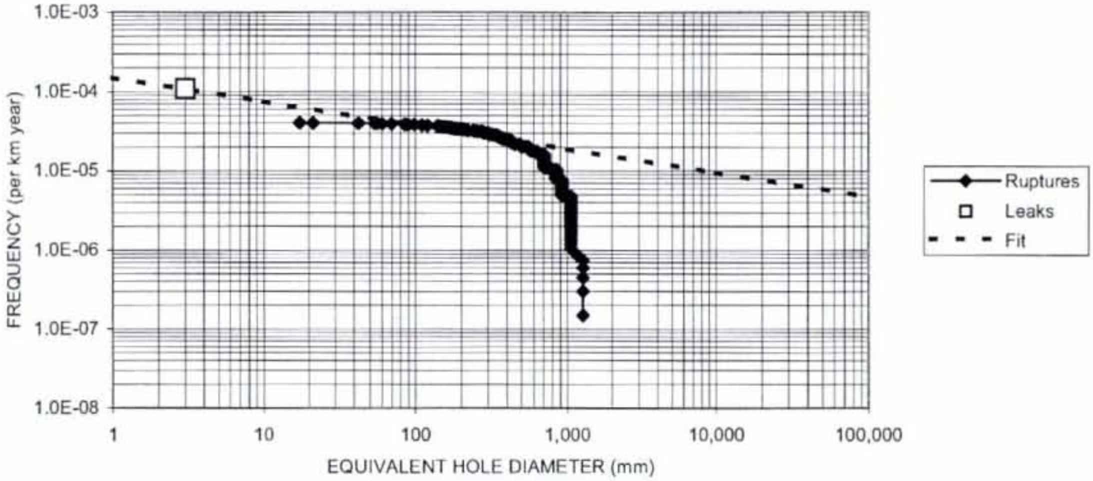


Figure I-3 Gas Transmission Pipeline Hole Size Distribution, 1986-96

The following hole size distribution provides a good fit to the leak frequency and rupture data below 400 millimeter equivalent diameter, as shown in the figure. Using a maximum hole diameter of 1.4D is a convenient representation of the truncation at twice the pipe cross-sectional area:

$$F(d) = 1.5 \times 10^{-4}\ d^{-0.3} \text{ for } 3 \text{ mm} \le d \le 1.4D \text{ mm}$$

where:

F(d)	=	frequency of leaks exceeding diameter d (per km-year)
d	=	equivalent diameter of leak (mm)
D	=	diameter of pipeline (mm)

I.2.5.4 Incident Causes

Table I-11 summarizes the causes of the incidents in the DOT database. Third party impacts are dominant for both ruptures and non-leak incidents.

Table I-11 Causes of Gas Transmission Pipeline Incidents, 1986-96

Cause	% of Ruptures	% of Leaks	% of Other	% of Total
Construction/operating error	14	19	8	14
Corrosion	31	33	2	23
Damage by outside force	41	31	53	41
Other	14	16	38	22
TOTAL	100	100	100	100

I.2.5.5 Effect of Pipeline Diameter

Figure I-4 shows the effect of pipeline diameter on the incident frequency, calculated from the DOT incident and population databases for gas transmission pipelines. The results are plotted on a base of mean pipeline size in the incident data, since the mean sizes in the population data are unknown. The results are sensitive to the treatment of the 15% of incidents for which no pipeline size was recorded. If these incidents are all allocated to the smallest size category (less than four inches), then this appears to have the highest frequency. This was the conclusion from previous analyses. However, the incidents with no pipeline size were not leaks from the pipeline. It would be preferable to neglect these incidents. Then the middle size category (ten to twenty inches) appears to have the highest frequency. It is concluded that there is no clear effect of pipeline diameter on the leak frequencies.

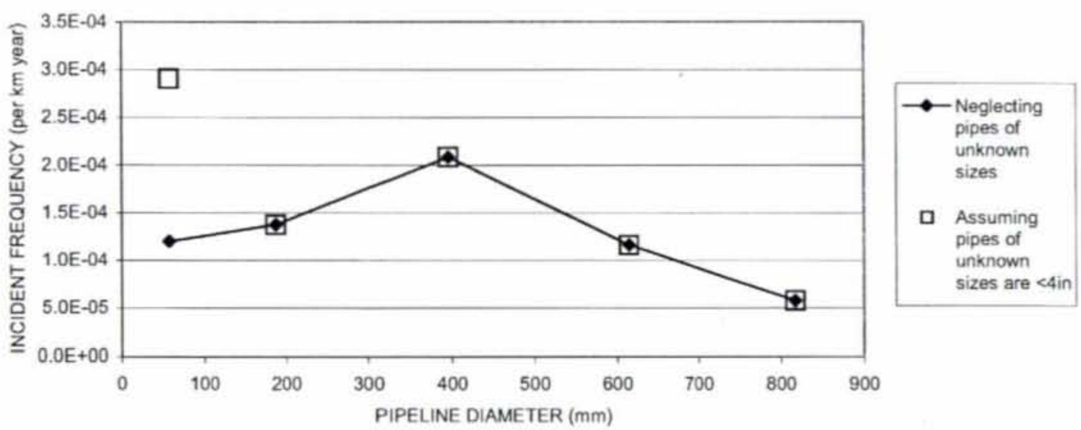


Figure I-4 Effect of Diameter on Gas Pipeline Incident Frequency, 1986-96

I.2.5.6 Effect of Service Type

The DOT incident and population data are divided into transmission and distribution lines, offshore and onshore. The two databases do not fully match, and the following assumptions have been made:

- Offshore pipelines are those recorded as Class 0 in the incident data.
- Transmission pipelines include those recorded as "transmission line of distribution system" in the incident data.

Table I-12 shows the frequencies for the different types of line, expressed as fractions of the overall frequency per kilometer-year. These can be multiplied by the overall frequencies above to estimate the frequency for a specific service type.

Table I-12 Frequency Ratio for Gas Transmission Pipeline Service, 1986-96

Service Type	Ruptures	Leaks + Ruptures	All Incidents
Onshore transmission	1.0	0.8	0.9
Onshore gathering	0.5	0.7	0.6
Onshore total	1.0	0.8	0.8
Offshore transmission	2.0	7.1	6.0
Offshore gathering	2.5	4.5	3.8
Offshore total	2.2	6.4	5.4
TOTAL	1.0	1.0	1.0

This shows that offshore pipelines have higher frequencies, but there are relatively few of these in the database; this has little effect on the overall frequency. The leak frequency shows the effect of associated offshore equipment (i.e. risers, topside processing equipment, pig launchers, etc), and the factor of 2.2 for ruptures is considered to be the best indicator of relative leak frequency. Onshore gathering pipelines have lower than average frequencies by approximately a factor of two. The frequencies for offshore gathering lines are uncertain due to the high proportion of offshore lines for which the type is not specified in the database.

I.2.6 California Pipelines Leak Frequency Data

I.2.6.1 Introduction

In 1993, the CSFM published an analysis of leak rates from regulated pipelines in the state during the 1980s (CSFM, 1993). What is fairly unique about this study compared to other US data sources is the following:

- There was no lower threshold for reporting – that is, in principle, leaks of any size were reported.
- The data were sorted by several design and operating variables of interest.

The impact of these variables on expected pipeline reliability is reviewed next.

I.2.6.2 Key Design and Operating Variables

Among the key variables identified in this and other analyses of pipeline data are: (1) operating temperature, (2) pipeline age, and (3) pipe diameter. For the conditions of the pipeline, the California data suggest the following:

Variable	Conditions	California Leak Rate (per 1000 mile-years)	Selected Subset of California Data	Trend
Operating temperature	50-60 F	2.38	Pipelines operating at less than 70 F	Failure rates increase with increasing temperature
Pipeline age	30 years, 38 years (currently)	4.17, 8.08	Pipelines 26-35 years old, and 36-45 years old, respectively.	Failure rates increase with increasing age
Pipeline diameter	16", 20"	3.49	Pipelines 16-20" in diameter	Failure rates decrease with increasing pipe diameter

These trends are consistent with what can be deduced from other pipeline databases, although the absolute leak rates are much higher in the California database (presumably because of the low reporting threshold).

A closer analysis of these three variables in the California database reveals that pipeline diameter may not have the impact on failure rates that it appears to have; specifically, the fact that failure rates decline with increasing pipeline diameter appears to result primarily from the fact that larger diameter pipelines tend to be much newer than smaller lines.

In fact, a very good correlation can be developed for the California data based on age and temperature:

$$\text{Leak Rate (per 1000 mile-years)} = [0.0027 \times (\text{age}) \times (\text{temperature})] - 0.80$$

where age is expressed in years, and temperature in degrees Fahrenheit.

I.2.6.3 Other Variables

The California study considers several other variables. Some of these are not discussed below - not because they are not important, but because it is too difficult to isolate the impact of the variable from the influence of temperature and age. Others of common interest to people are briefly assessed next, but were not used as modifiers for the various reasons described. The net effect of not including these other variables, if any, is to make the resulting failure rate conservatively high.

The California data are sorted by three grades of pipe: (1) X-Grade, (2) A53 and Grade B, and (3) Other. A53/Grade B and Other pipe had failure rates 2.7 and 14 times that of X-Grade, respectively, in spite of average operating temperatures that were lower than that used on the X-Grade pipe.

However, the average X-Grade pipe in the California database was installed in 1960 and the others in 1950 on average. The preponderance of data overall is from X-Grade pipe.

I.2.7 Modification of Frequencies for Specific Pipelines

I.2.7.1 Effect of Pipeline Wall Thickness

Increasing the wall thickness of a pipeline, all other parameters being constant, gives greater resistance to external impacts, corrosion and material defects. It should therefore reduce the leak frequency. However, if thickness has been increased to counteract additional hazards, such as high pressure or corrosive environments, this may not change the leak frequency compared to standard conditions.

Figure I-5 shows the effect of wall thickness on external interference and corrosion leak frequencies from the EGIG data for 1970-92 (EGIG, 1993). The results are plotted on a base of the mid-point in each thickness category, which makes the lateral positions on the plots uncertain. It is generally considered that corrosion cannot cause leaks for pipes with over 15 millimeter wall thickness (Hill and Catmur, 1994), as there has been no experience of such events. Extrapolation of this plot suggests that such leaks may occur, but at an extremely low frequency.

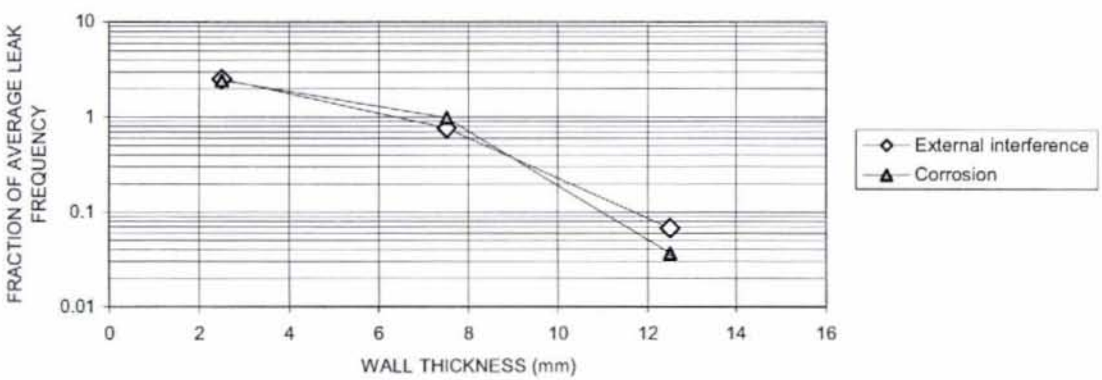


Figure I-5 Effect of Wall Thickness on Third Party and Corrosion Leak Frequencies

The shape of the plot partly reflects the fact that greater wall thickness is usually specified for large diameter pipelines, and hence it cannot be considered additional to any diameter effect. The best available attempt to consider the effects of wall thickness in isolation, at a constant diameter, suggests that leak frequency is inversely proportional to the diameter squared. Hence, the leak frequency for a pipe of non-standard thickness can be estimated as:

$$F(D, t) = F(D) \times (t_s/t)^2$$

where:

F(D, t)	=	frequency of any leak (per km-year) for pipeline diameter D and thickness t
F(D)	=	frequency of any leak (per km-year) for pipeline diameter D and standard thickness
T	=	pipeline wall thickness (mm)
t_s	=	nominal pipeline wall thickness (mm)

These are based on a judgmental model, in the absence of any data showing how leak frequency varies with independent changes in diameter and wall thickness.

I.2.7.2 Effect of Design Factor

Pipeline operating conditions are often expressed in terms of a design factor, which is the circumferential stress in the pipe wall at the operating conditions, expressed as a fraction of the specified minimum yield stress of the pipe material. For pipelines with design factors 0.5 to 0.7, the maximum stable hole sizes are usually in the region of 100 millimeter equivalent diameter. There is no need to model leaks between this size and rupture, since any such holes would rapidly grow into ruptures.

This limit is obtained by considering the growth of small flaws in the pipe. Such flaws may be caused by impacts, corrosion or inherent defects. Under normal operating stresses, these flaws grow through the thickness of the pipe until they form a leak. If the flaw is in the form of a crack, and the crack is above a certain critical length, it will then grow rapidly until complete rupture of the pipe occurs.

Ruptures due to crack growth are theoretically virtually impossible if the design factor is less than 0.3, or if the wall thickness is over 19 millimeter and the design factor is less than 0.5 (Townsend and Fearnehough, 1986). Ruptures may still occur from natural hazards and massive impacts, but the probability of these is low. Some analyses have neglected the probability of ruptures altogether in these conditions.

I.2.7.3 Effect of Depth of Cover

The leak frequencies are based on combined experience of buried and surface pipelines, but most are buried.

The United Kingdom Health and Safety Executive judgments on the effect of depth of cover on the external impact frequency are (ADL, 1999):

- 0% reduction for 0.9 meter depth
- 25% reduction for 1.5 meter depth
- 50% reduction for 2.0 meter depth
- 99% reduction for 3.0 meter depth

Figure I-6 compares these to data from EGIG for 1970-92, showing some consistency. The EGIG data shows a factor of 3.5 increase in third party damage frequency for cover of 0 to 0.8 meters.

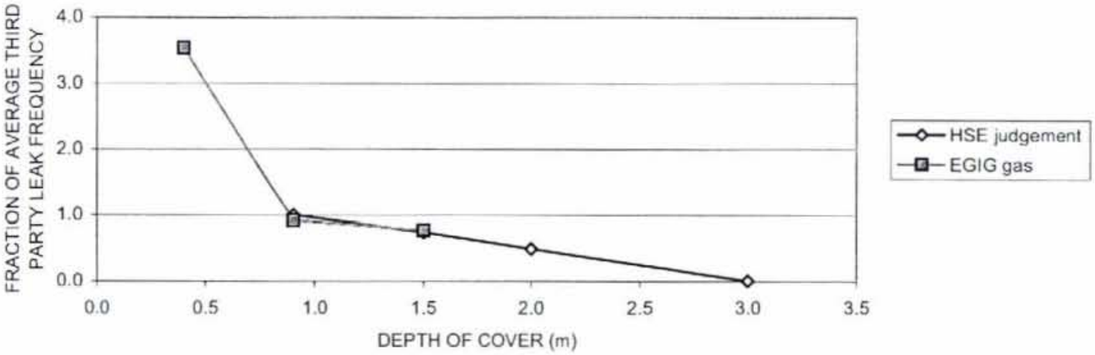


Figure I-6 Effect of Depth of Cover on Third Party Leak Frequencies

I.2.7.4 Effect of Corrosion Protection

Corrosion protection (anti-corrosion coating or cathodic protection) would be expected to reduce the corrosion frequency. Their effects on corrosion incident frequencies in the US gas pipeline data are given in **Table I-13**. These can be multiplied by the corrosion frequencies (based on the overall frequency and the proportion due to corrosion given above) to estimate the corrosion frequency for specific protection type.

Table I-13 Corrosion Frequency Ratios for US Gas Pipelines, 1986-96

Protection Type	All Incidents
Pipelines with corrosion coating and cathodic protection	0.09
Pipelines with corrosion coating but not cathodic protection	12.4
Pipelines with cathodic protection but not corrosion coating	17.4
Pipelines with neither cathodic protection nor corrosion coating	1.5
All pipelines with corrosion coating	0.14
All pipelines with cathodic protection	0.9
All pipelines without corrosion coating	12.0
All pipelines without cathodic protection	2.7
TOTAL	1.0

These results show a very large effect of corrosion protection on corrosion incident frequencies. Some anomalies arise because of the significant number of incidents where the corrosion protection is not recorded in the database. The low corrosion frequency for pipelines with no corrosion protection may result from these being in less corrosive environments.

CSFM (1993) shows a factor of five difference between liquid pipelines with and without cathodic protection, which is slightly greater than the overall factor of three for gas lines in the DOT data. There was no significant difference between impressed current and sacrificial anode types. The study also quantified the effects of various external pipe coating types.

I.2.7.5 Effect of Pipeline Route

Urban locations will increase the frequencies in various ways. The following assumptions have been used in previous studies:

- Location along the edge of a main road (DNV Technica 1992b, C3006):
  - No Change if barriers in place
  - Material defect increased by a factor of 2
  - Construction defect increased by a factor of 3 due to difficulty of access.
- Location along the central reservation of a main road (DNV Technica 1992b, C3006):
  - External impact frequency increased by a factor of 1.5 due to road maintenance activities.

I.2.7.6 Effect of Intelligent Pigging

The effect of intelligent pigging has been represented by (DNV Technica 1992a, C3239) and other sources for frequencies outside the normal range of four to seven years:

Table I-14 Intelligent Pigging Modification Factors

Frequency of Intelligent Pigging	Corrosion Modifying Factor	Defect Modifying Factor
0-3 years	0.5	0.5
4-7 years	1.0	1.0
>7 years	2.0	2.0

CSFM (1993) also presents an analysis of the effects of internal inspection.

I.2.7.7 Effect of Decade of Construction

The effect of the decade of construction of pipelines was examined by Kiefner and Trench (2001) in a report for the API Pipeline Committee. A key finding from the report was that due to materials of construction, welding techniques, and inspection methods that failures due to material/construction defects were significantly less likely for pipelines constructed in the 1970s and later relative to those constructed from the 1930s through the 1960s. Pipelines constructed prior to the 1930s fared much worse. Combining the effects of longitudinal welds (much greater differential) and girth welds, DNV has estimated the following adjustment factors for the decade of construction:

- Construction prior to 1930s – 2.0
- Construction 1930s through 1960s - 1.0
- Construction 1970s and Later - 0.5

I.3 References and Literature Review

ADL, 1999 — "*Risks from Gasoline Pipelines in the United Kingdom*", Arthur D Little, Contract Research Report 206/1999, Health & Safety Executive, HSE Books.

AME, 1998 — AME (1998), "*PARLOC 96: The Update of Loss of Containment Data for Offshore Pipelines*", Offshore Technology Report OTH 551, Health & Safety Executive, HSE Books.

Batelle, 1980 — Batelle Columbus Laboratories. "*An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines, 1970-78*", Report by Batelle Columbus Laboratories to Pipeline Research Committee, American Gas Association, NG-18 Report no 121, September 1980.

CCPS, 1989 — American Institute of Chemical Engineers, Center for Chemical Process Safety, "*Chemical Process Quantitative Risk Analysis*", New York, 1989.

CSFM, 1993 — California State Fire Marshal, "*Hazardous Liquid Pipeline Risk Assessment*", California, USA, 1993.

DNV Technica, 1992a — DNV Technica, "*South West Queensland Pipeline Failure Rate and Ignition Probability Database*", C3239, Santos LTD., 1992

DNV Technica, 1992 — DNV Technica, *"Risk and Environmental Impact Assessment of Route Options for the High Pressure Gas Pipeline between Gadong and Jerudong"*, C3006, Brunei Shell Petroleum Sendiran, Berhad, 1992.

DNV Technica, 1995 — DNV Technica, *"Hazard Assessment Study for the Natural Gas Supply into Black Point and Castle Peak Power Stations"*, K5429, Castle Peak Power Company Limited, 1995

DNV, 2005 — Det Norske Veritas, Activity Responsible Function, http://one.dnv.com/risknet/about/about-index.heml#procedures.

DOT, 1970 — United States Department of Transportation "*Gas Transmission and Gathering Systems and Leak or Test Failure Reports - Transmission and Gathering Systems*", Annual Reports, Research and Special Programs Administration, Office of Pipeline Safety, Washington DC, USA, 1970.

DOT, 1989 — United States Department of Transportation, "*Annual Report on Pipeline Safety*", Research and Special Programs Administration, Office of Pipeline Safety, Washington DC, USA, 1989.

DOT, 2005a — United States Department of Transportation, *"Liquid Accident Yearly Summaries (1986-2004")*, (http://ops.dot.gov/stats/stats.htm)

DOT, 2005b	United States Department of Transportation, *"Natural Gas Incident Yearly Summaries for Transmission Operators (1986-2004")*, (http://ops.dot.gov/stats/stats/htm)
EGIG, 1993	European Gas Pipeline Incident Data Group, "*Gas Pipeline Incidents, Report 1970-1992"*, Gasunie, Groningen, the Netherlands, 1993.
Eiber, R.J., Jones, D. J. and Kramer, G.S., 1987	Eiber, R.J., D.J. Jones and G.S. Kramer. "*Outside Force Causes Most Natural Gas Pipeline Failures*", Oil & Gas Journal, 16 March 1987.
Fearnehough, G.D., 1986	Fearnehough, G.D. "*Safe Pipeline Performance*", Conference on Welding and Performance of Pipelines, Welding Institute, November 1986.
Hill, R.T., and Catmur, J.R., 1994	Hill, R.T. and J.R. Catmur. *"Risks from Hazardous Pipelines in the United Kingdom"*, Arthur D Little, HSE Contract Research Report 82/1994, HSE Books.
HSE, 1978	United Kingdom Health and Safety Executive, "*A Safety Evaluation of the Proposed St Fergus to Mossmorran Natural Gas Liquids and St Fergus to Boddam Gas Pipelines*", 1978.
HSE. 2005	United Kingdom Health and Safety Executive, Hydrocarbon Releases Database System, www/hse.gov.uk/hcr3/, 2005
Kiefner, J.F. and Trench, C.J., 2001	Kiefner, J.F. and C.J. Trench. *"Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction"*, Kiefner & Associates and Allegro Energy Group report for American Petroleum Institute's Pipeline Committee, December, 2001.
Kiefner, J.F., Kiefner, B.A. and Vieth, P.H., 1999	Kiefner, J.F., B.A. Kiefner and P.H. Vieth. *"Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Through 1996"*, Kiefner & Associates Report to DOT and API, API Publication 1158, 1999.
Levin, S.I. and Kharionovsky, V.V., 1993	Levin, S.I. and V.V. Kharionovsky. "*Causes and Frequency of Failures on Gas Mains in the USSR*", Pipes & Pipelines International, July/Aug 1993. [DNV Technica source LO 881]
Lyons, D. 1994	Lyons, D. *"CONCAWE Pipeline Performance Report and Analysis"*, CONCAWE Pipeline Integrity Management Seminar, Brussels, October 1994.
Mannan, 2005	Mannan, S. "*Lee's Loss Prevention in the Process Industries Hazard Identification Assessment and Control"*, Appendix I Case Histories", AI/I, Third Edition, 2005

Mather, J. and Lines, I.G., 1999	Mather, J. and Lines, I.G. "*Assessing the Risk from Gasoline Pipelines in the United Kingdom Based on a review of Historical Experience*", WS Atkins, HSE Contract Research Report 2101999, HSE Books, 1999.
Office of Pipeline Safety, 2006	U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Pipeline Statistics*. http://ops.dot.gov/stats/stats.htm#average, May 1, 2006.
Townsend, N.A. and Fearnehough, G.D., 1986	Townsend, N.A. and Fearnehough, G.D. "*Control of Risk from UK Gas Transmission Pipelines*", 7th Symposium on Line Pipe Research, AGA, Houston, USA, October 1986.
Rocky Mountain Institute, 2001	Rocky Mountain Institute, *Updates to the Annotations*, Amory Lovins, October 7, 2001.